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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)

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

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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Southern California Edison Company	**End of** 2020/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: https://forms.ferc.gov/. 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 https://www.ferc.gov/ferc-online/overview.

(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 https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Southern California Edison Company	02 Year/Period of Report End of 2020/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 Aaron Moss	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)* 04/14/2021

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 Aaron Moss	03 Signature Aaron Moss	04 Date Signed *(Mo, Da, Yr)* 04/14/2021
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	04/14/2021	End of 2020/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

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	04/14/2021	End of 2020/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.

Mr. Aaron D. Moss, VP and Controller
Location: 2244 Walnut Grove Avenue, 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 electric utility service in the state of California and electricity, 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

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	04/14/2021	End of 2020/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Edison International holds control over respondent by way of 100% ownership of respondent's common stock.

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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 Material Supply LLC	Company engaged in providing	100%	
7	a Delaware Limited Liability Company	procurement, inventory and		
8		warehousing services to		
9		Southern California Edison.		
10				
11	Mono Power Company	Inactive.	100%	
12	a California Company			
13				
14				
15	Southern States Realty (Formerly Southern	Corporation engaged	100%	
16	Surplus Realty Co.)	in holding real estate		
17	a California Corporation	interests.		
18				
19	SCE Trust II	Delaware business trust	100%	
20		organized to act as a		
21		financing vehicle.		
22				
23				
24	SCE Trust III	Delaware business trust	100%	
25		organized to act as a		
26		financing vehicle.		
27				

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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 IV	Delaware business trust	100%	
2		organized to act as a		
3		financing vehicle.		
4				
5	SCE Trust V	Delaware business trust	100%	
6		organized to act as a		
7		financing vehicle.		
8				
9	SCE Trust VI	Delaware business trust	100%	
10		organized to act as a		
11		financing vehicle.		
12				
13	SCE Trust VII	Delaware business trust	100%	
14		organized to act as a		
15		financing vehicle.		
16				
17	SCE Trust VIII	Delaware business trust	100%	
18		organized to act as a		
19		financing vehicle.		
20				
21	SCE Recovery Funding LLC	Company engaged in owning and	100%	
22		servicing recovery property		
23		and issuing and making		
24		payments on recovery bonds.		
25				
26				
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	04/14/2021	End of 2020/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	SCE Equipment Trust I	Delaware business trust	100%	
2		organized to hold the legal		
3		title of leased vehicles and		
4		equipment.		
5				
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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 Occidental Petroleum Corporation.

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

Edison Material Supply LLC

Respondent is the only member of Edison Material Supply LLC. In April 2018, FERC approved SCE's use of equity method of accounting waiver for Edison Material Supply, LLC. (Docket No. AC18-56-000).

Schedule Page: 103 Line No.: 19 Column: d

SCE Trust II

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

Schedule Page: 103 Line No.: 24 Column: d

SCE Trust III

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

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

SCE Trust IV

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

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

SCE Trust V

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

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

SCE Trust VI

Respondent owns 100% of Common Stock as of 6/27/2017.

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

SCE Trust VII

Respondent is the depositor.

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

SCE Trust VIII

Respondent is the depositor.

Schedule Page: 103.1 Line No.: 21 Column: d

SCE Recovery Funding LLC

Respondent is the only member of SCE Recovery Funding LLC.

Schedule Page: 103.2 Line No.: 1 Column: d

SCE Equipment Trust I

Respondent is the beneficial owner of the Trust as of 10/16/2009.

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	04/14/2021	End of 2020/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 and Chief Executive Officer	Kevin M. Payne	620,864
2			
3	Executive Vice President	Steven D. Powell	400,000
4			
5	Senior Vice President and Chief Financial Officer	William M. Petmecky III	362,765
6			
7	Senior Vice President & General Counsel	Jennifer R. Hasbrouck	341,623
8	(effective 5/2/2020)		
9			
10	Senior Vice President & General Counsel	Russell C. Swartz	127,667
11	(end 5/1/2020)		
12			
13	Senior Vice President	Phillip R. Herrington	385,643
14			
15	Senior Vice President	Jill C. Andersen	321,679
16			
17	Senior Vice President	Kevin E. Walker	77,902
18	(end 3/21/2020)		
19			
20			
21			
22			
23			
24			
25	The amount set forth in Col (c), "Salary for Year" is		
26	the salary earned for 2020 by the executive officer, and		
27	does not include any other compensation. The executive		
28	officers listed above are Southern California Edison		
29	Company's executive officers for purposes of Rule 3b-7		
30	of the Securities Exchange Act of 1934.		
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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	04/14/2021	End of 2020/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	Jeanne Beliveau-Dunn	2244 Walnut Grove Avenue
2		Rosemead, California 91770
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4		
5	Michael C. Camuñez	2244 Walnut Grove Avenue
6		Rosemead, California 91770
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9	Vanessa C.L. Chang	2244 Walnut Grove Avenue
10		Rosemead, California 91770
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13	James T. Morris	2244 Walnut Grove Avenue
14		Rosemead, California 91770
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17	Timothy T. O'Toole	2244 Walnut Grove Avenue
18		Rosemead, California 91770
19		
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21	Kevin M. Payne	2244 Walnut Grove Avenue
22	President and Chief Executive Officer	Rosemead, California 91770
23		
24		
25	Pedro J. Pizarro	2244 Walnut Grove Avenue
26		Rosemead, California 91770
27		
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29	Carey A. Smith	2244 Walnut Grove Avenue
30		Rosemead, California 91770
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32		
33	Linda G. Stuntz	2244 Walnut Grove Avenue
34		Rosemead, California 91770
35		
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37	William P. Sullivan	2244 Walnut Grove Avenue
38		Rosemead, California 91770
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41	Peter J. Taylor	2244 Walnut Grove Avenue
42		Rosemead, California 91770
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44		
45	Keith Trent	2244 Walnut Grove Avenue
46		Rosemead, California 91770
47	Please note: The respondent does not have a Board	
48	Executive Committee.	

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	04/14/2021	End of 2020/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	(TRBAA) ER20-268, ER19-220, ER18-154, ER17-250,
2	FERC Electric Tariff, Volume No. 6	(RSBAA) ER20-248, ER19-219, ER18-184, ER17-232,
3	FERC Electric Tariff, Volume No. 6	(TACBAA) ER20-1452, ER19-1480, ER18-1207,
4	FERC Electric Tariff, Volume No. 6	(Base TRR) ER20-1720, ER20-1382, ER20-1057,
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Schedule Page: 106   Line No.: 1   Column: b

FERC Electric Tariff, Volume No. 6: ER16-175, ER15-259, ER06-788, ER03-338, ER97-2355

Schedule Page: 106   Line No.: 2   Column: b

FERC Electric Tariff, Volume No. 6: ER16-176, ER15-216, ER05-763, ER04-1209, ER04-890, ER03-142, ER01-315

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

FERC Electric Tariff, Volume No. 6: ER17-1345, ER16-1272, ER15-1399, ER14-1604, ER13-1174, ER11-3248, ER05-506, ER03-338, ER01-832

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

FERC Electric Tariff, Volume No. 6: ER19-1553, ER18-169, ER17-914, ER16-2433, ER16-1393, ER16-1292, ER16-686, ER15-1449, ER14-2788, ER13-1253, ER13-1190, ER11-3697

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	04/14/2021	End of 2020/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	20191031-5220	10/30/2019	ER20-268	2020 TRBAA Update	FERC Electric Tariff Vol. No. 6
2	20191031-5002	10/30/2019	ER20-248	2020 RSBAA Update	FERC Electric Tariff Vol. No. 6
3	20190329-5211	03/29/2019	ER19-1480	2019 TACBAA Update	FERC Electric Tariff Vol. No. 6
4	20200331-5147	03/31/2020	ER20-1452	2020 TACBAA Update	FERC Electric Tariff Vol. No. 6
5	20190411-5001	04/11/2019	ER19-1553	2019 TO2019A Successor	FERC Electric Tariff Vol. No. 6
6	20200221-5091	02/21/2020	ER20-1057	Formula Rate Revision	FERC Electric Tariff Vol. No. 6
7	20200325-5125	03/25/2020	ER20-1382	Formula Rate Revision	FERC Electric Tariff Vol. No. 6
8	20200430-5309	04/30/2020	ER20-1720	Formula Rate Revision	FERC Electric Tariff Vol. No. 6
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Schedule Page: 1061 Line No.: 5 Column: d

2019 TO2019A Successor Formula Transmission Rate

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

Formula Rate Revision - Depreciation Update Filing

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

Formula Rate Revision - Post Retirement Benefits Other than Pensions

Schedule Page: 1061 Line No.: 8 Column: d

Formula Rate Revision - Order 864 Filing

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	04/14/2021	End of 2020/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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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Question 1 Franchises

Quarter ending March 31, 2020:
There were no changes in franchise rights for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes in franchise rights for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes in franchise rights for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes in franchise rights for quarter ending December 31, 2020

Question 2 Acquisition of ownership in other companies

Not applicable

Question 3 Purchase or sale of an operation unit or system

Purchase or sale of an operation unit or system for 2020:

Quarter ending March 31, 2020:

1. A.L. 3671-E – Sale of streetlight facilities to the City of Industry
2. A.L. 3911-E – Sale of streetlight facilities to the City of Laguna Beach
3. A.L. 3819-E – Sale of streetlight facilities to the City of Menifee
4. A.L. 3770-E – Sale of streetlight facilities to the City of Goleta

Quarter ending June 30, 2020:
There were no new purchases or sales of an operation unit or systems for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no new purchases or sales of an operation unit or systems for quarter ending September 30, 2020.

Quarter ending December 31, 2020:

1. A.L. 3825-E – Sale of streetlight facilities to the City of Bell
2. A.L. 3826-E – Sale of streetlight facilities to the City of Pico Rivera

Question 4 Important Leaseholds

Quarter ending March 31, 2020:
There were no changes in important leaseholds for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes in important leaseholds for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes in important leaseholds for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes in important leaseholds for quarter ending December 31, 2020.

Question 5 Important extension or reduction of transmission or distribution system

Quarter ending March 31, 2020:
There were no major/significant extensions or reductions of transmission or distribution system for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no major/significant extensions or reductions of transmission or distribution system for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no major/significant extensions or reductions of transmission or distribution system for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no major/significant extensions or reductions of transmission or distribution system for quarter ending December 31, 2020.

Question 6 Obligations

Long-Term Debt / Security Issuances for quarter ending March 31, 2020:

Taxable

Quarter ending March 31, 2020:

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2019C (Reopener)	1/09/2020	$100	2.85%	8/01/2029	No. 16-02-018 dated February 25, 2016
Series 2020A	1/09/2020	$500	3.65%	2/01/2050	No. 16-02-018 dated February 25, 2016
Series 2020A (Reopener)	3/09/2020	$700	3.65%	2/01/2050	No. 16-02-018 dated February 25, 2016 and No. 18-06-008 dated June 27, 2018
Series 2020B	3/09/2020	$400	2.25%	6/01/2030	No. 16-02-018 dated February 25, 2016 and No. 18-06-008 dated June 27, 2018

Quarter ending June 30, 2020:

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2018E (Reopener)	4/02/2020	$600	3.70%	8/01/2025	No. 08-10-014 dated October 2, 2008

Quarter ending September 30, 2020
No taxable debt security issuances for quarter ending September 30, 2020.

Quarter ending December 31, 2020:

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2020C	10/01/2020	$350	1.20%	2/01/2026	No. 20-04-016 dated April 23, 2020

Tax-Exempt

Quarter ending March 31, 2020:
No tax-exempt debt security issuances for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
No tax-exempt debt security issuances for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
No tax-exempt debt security issuances for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
No tax-exempt debt security issuances for quarter ending December 31, 2020.

Short-Term Obligations

Quarter ending March 31, 2020:
The SCE short term debt as of March 31,2020 consisted of commercial paper and a $475 million term loan. The $475 million term loan was drawn on March 11, 2020 and it was outstanding as of March 31, 2020. The interest rate on the $475 million term loan was 1.34% .

At March 31, 2020 there was no commercial paper outstanding.

Quarter ending June 30, 2020:
At June 30, 2020 the $475 million term loan drawn on March 11, 2020 was outstanding. There was no commercial paper outstanding.

Quarter ending September 30, 2020:
The SCE short term debt in the 3rd quarter 2020 consisted of commercial paper, a $475 million AB 1054 term loan, and draws against the AB 1054 credit facility (wildfire risk mitigation capital expenditures funding). Please refer to the Notes to the Financials for further detail on the AB 1054 financing and funding related to credit agreements and short-term debt.

At September 30, 2020 SCE had $622 million of commercial paper outstanding, net of discount, at a weighted-average interest rate of 0.29%. The commercial paper maturities ranged from October 1, 2020 to January 11, 2021.

The $475 million AB 1054 term loan was drawn on March 11, 2020 and it was outstanding as of September 30, 2020. The interest rate on the $475 million AB 1054 term loan was LIBOR + 0.60% (0.80% as of September 30, 2020).

At September 30, 2020 SCE had drawn $654 million from the AB 1054 credit facility at a weighted average rate of LIBOR + 0.65% (0.81%).

Quarter ending December 31, 2020:
The SCE short term debt in the 4th quarter 2020 consisted of commercial paper, a $475 million AB 1054 term loan, and draws against the AB 1054 credit facility (wildfire risk mitigation capital expenditures funding), and $900 million 364-day floating rate first and

refunding mortgage bonds. Please refer to the Notes to the Financials for further detail on the AB 1054 financing and funding related to credit agreements and short-term debt.

At December 31, 2020 SCE had $725 million of commercial paper outstanding, net of discount, at a weighted-average interest rate of 0.43%. The commercial paper maturities ranged from January 4, 2021 to January 29, 2021.

The $475 million AB 1054 term loan was drawn on March 11, 2020 and it was outstanding as of December 31, 2020. The interest rate on the $475 million AB 1054 term loan was LIBOR + 0.60% (0.77% as of December 31, 2020).

At December 31, 2020 SCE had drawn $495 million from the AB 1054 credit facility at a weighted average rate of LIBOR + 0.65% (0.80%).

The $900 million 364-day floating rate first and refunding mortgage bonds were issued on December 4, 2020 and were outstanding as of December 31, 2020. The interest rate on the $900 million 364-day floating rate first and refunding mortgage bonds was LIBOR + 0.27% (0.50% as of December 31, 2020).

Preferred Security Issuances

Quarter ending March 31, 2020:
No preferred stock security issuances for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
No preferred stock security issuances for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
No preferred stock security issuances for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
No preferred stock security issuances for quarter ending December 31, 2020.

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

Quarter ending March 31, 2020:
There were no changes to articles of incorporation or amendments to charter for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes to articles of incorporation or amendments to charter for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes to articles of incorporation or amendments to charter for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes to articles of incorporation or amendments to charter for quarter ending December 31, 2020.

Question 8 Wage Scale Changes

Quarter ending March 31, 2020:

1. General increases for IBEW employees was 4.00%, effective January 1, 2020. The estimated annual cost resulting from the increase in base wages is $16,710,524.
2. General increases for UWUA employees was 3.00%, effective January 1, 2020. The estimated annual cost resulting from the increase in base wages is $50,475.
3. Annual merit increase budget for non-represented and non-executive employees was 3.5%, effective February 17, 2020. The estimated annual cost resulting from the increase in base wages is $33,588,990.

Quarter ending June 30, 2020:
There are no wage scale changes for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There are no wage scale changes for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
The final phase (Phase 5) of the Compensation Design Project (CDP) was completed in the 4th quarter of 2020, effective 12/21/2020. The CDP was a company-wide effort to move all Edison jobs to a common and competitive market-based pay salary structure. All non-represented, non-executive positions are now in our new graded structure.

Question 9 Materially important legal matters.

2017/2018 Wildfire/Mudslide Events Litigation

The Thomas Fire, Koenigstein Fire, Montecito Mudslides and Woolsey Fire (each as defined below) are collectively referred to as the “2017/2018 Wildfire/Mudslide Events.” Multiple lawsuits related to the 2017/2018 Wildfire/Mudslide Events naming SCE as a defendant have been filed by three categories of plaintiffs: individual plaintiffs, subrogation plaintiffs and public entity plaintiffs. A number of the lawsuits also name Edison International as a defendant and some of the lawsuits were filed as purported class actions. The Thomas and Koenigstein Fires and Montecito Mudslides lawsuits are being coordinated in the Los Angeles Superior Court. The Woolsey Fire lawsuits have also been coordinated in the Los Angeles Superior Court. Because potential plaintiffs can still timely file claims related to the 2017/2018 Wildfire/Mudslide Events, SCE expects to be the subject of additional lawsuits related to the events. The litigation could take a number of years to be resolved because of the complexity of the matters and number of plaintiffs.

Thomas Fire and Koenigstein Fire Litigation

Wildfires in SCE's territory in December 2017 and November 2018 caused loss of life, substantial damage to both residential and business properties, and service outages for SCE customers. The investigating government agencies, the Ventura County Fire Department ("VCFD") and California Department of Forestry and Fire Protection ("CAL FIRE"), have determined that the largest of the 2017 fires in SCE's territory originated on December 4, 2017, in the Anlauf Canyon area of Ventura County (the investigating agencies refer to this fire as the "Thomas Fire"), followed shortly thereafter by a second fire that originated near Koenigstein Road in the City of Santa Paula (the "Koenigstein Fire"). The December 4, 2017 fires eventually burned substantial acreage in both Ventura and Santa Barbara Counties. According to CAL FIRE, the Thomas and Koenigstein Fires, collectively, burned over 280,000 acres, destroyed or damaged an estimated 1,343 structures and resulted in two confirmed fatalities.

As of February 18, 2021, SCE was aware of at least 295 lawsuits, representing approximately 4,000 plaintiffs, related to the Thomas and Koenigstein Fires naming SCE as a defendant. At least four of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura, Santa Barbara and Los Angeles Counties allege, among other things, negligence, inverse condemnation, trespass, private nuisance, and violations of the public utilities and health and safety codes. An initial trial for a limited number of plaintiffs, sometimes referred to as a bellwether trial, on certain fire only matters is currently scheduled for July 19, 2021. The bellwether trial date may be further delayed to provide SCE and certain of the individual plaintiffs in the Thomas and Koenigstein Fire litigation the opportunity to pursue settlements of claims under a program adopted to promote an efficient and orderly settlement process.

Montecito Mudslides Litigation

Some of the Thomas and Koenigstein Fires lawsuits claim that SCE and Edison International have responsibility for the damages caused by debris flows and flooding in Montecito and surrounding areas in January 2018 (the "Montecito Mudslides") based on a theory alleging that SCE has responsibility for the Thomas and/or Koenigstein Fires and further alleging that the Thomas and/or Koenigstein Fires proximately caused the Montecito Mudslides. According to Santa Barbara County initial reports, the Montecito

Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures, and resulted in 21 confirmed fatalities, with two additional fatalities presumed.

Seventy-two of the 295 lawsuits mentioned in the Thomas Fire and Koenigstein Fire Litigation section above allege that SCE has responsibility for the Thomas and/or Koenigstein Fires and that the Thomas and/or Koenigstein Fires proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. In addition to other causes of action, some of the Montecito Mudslides lawsuits also allege personal injury and wrongful death. A bellwether jury trial previously scheduled for October 12, 2020 was vacated due to the wide-spread disruption being caused by the COVID-19 pandemic.

Woolsey Fire Litigation

The largest of the November 2018 fires in SCE's territory, known as the "Woolsey Fire," originated in Ventura County and burned acreage in both Ventura and Los Angeles Counties. According to CAL FIRE, the Woolsey Fire burned almost 100,000 acres, destroyed an estimated 1,643 structures, damaged an estimated 364 structures and resulted in three confirmed fatalities. Two additional fatalities have been associated with the Woolsey Fire.

As of February 18, 2021, SCE was aware of at least 301 lawsuits, representing approximately 6,000 plaintiffs, related to the Woolsey Fire naming SCE as a defendant. At least two of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura and Los Angeles Counties allege, among other things, negligence, inverse condemnation, personal injury, wrongful death, trespass, private nuisance, and violations of the public utilities and health and safety codes. A bellwether jury trial is currently scheduled for June 1, 2021.

Settlements

In the fourth quarter of 2019, SCE paid $360 million to a number of local public entities to resolve those parties' collective claims arising from the 2017/2018 Wildfire/Mudslide Events (the "Local Public Entity Settlements").

In the third quarter of 2020, Edison International and SCE entered into an agreement (the "TKM Subrogation Settlement") under which all of the insurance subrogation plaintiffs' in the Thomas Fire, Koenigstein Fire and Montecito Mudslides litigation (the "TKM Subrogation Plaintiffs") collective claims arising from the Thomas Fire, Koenigstein Fire or Montecito Mudslides have been resolved. Under the TKM Subrogation Settlement, SCE paid the TKM Subrogation Plaintiffs an aggregate of $1.2 billion in October 2020 and also agreed to pay $0.555 for each dollar in claims to be paid by the TKM Subrogation Plaintiffs to their policy holders on or before July 15, 2023, up to an agreed upon cap.

In January 2021, Edison International and SCE entered into an agreement (the "Woolsey Subrogation Settlement") under which all of the insurance subrogation plaintiffs' in the Woolsey Fire litigation (the "Woolsey Subrogation Plaintiffs") collective claims arising from the Woolsey Fire have been resolved. Under the Woolsey Subrogation Settlement, SCE agreed to pay the Woolsey Subrogation Plaintiffs an aggregate of $2.2 billion by April 22, 2021. SCE has also agreed to pay $0.67 for each dollar in claims to be paid by the Woolsey Subrogation Plaintiffs to their policy holders on or before July 15, 2023, up to an agreed upon cap.

As of February 18, 2021, SCE has also entered into settlements with approximately one thousand individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation. In 2020 SCE entered into settlements with individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation under which it agreed to pay an aggregate of approximately $300 million to those individual plaintiffs. Between December 31, 2020 and February 18, 2021, SCE also entered into settlements with individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation under which it agreed to pay an aggregate of approximately $80 million to those individual plaintiffs.

Edison International and SCE did not admit wrongdoing or liability as part of any of the settlements described above.

Other claims and potential claims related to the 2017/2018 Wildfire/Mudslide Events remain. SCE continues to explore reasonable settlement opportunities with other plaintiffs in the outstanding 2017/2018 Wildfire/Mudslide Events litigation.

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

Quarter ending March 31, 2020:

None for the quarter ending March 31, 2020.

Quarter ending June 30, 2020:
None for the quarter ending June 30, 2020.

Quarter ending September 30, 2020:
None for the quarter ending September 30, 2020.

Quarter ending December 31, 2020:
None for the quarter ending December 31, 2020.

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 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.

Not applicable

Question 13

a) Changes in officers of the respondent.

Quarter ending March 31, 2020:

Officer Name	Title	Date First Elected	Effective Date	End Date (if applicable)
Colin E. Cushnie	Vice President	08/28/2014	08/28/2014	02/03/2020
William V. Walsh	Vice President	11/15/2019	02/03/2020	N/A
Kevin E. Walker	Vice President	11/8/2017	12/05/2017	03/20/2020
Natalie K. Schilling	Vice President	04/03/2020	04/13/2020	N/A
Russell C. Swartz	Senior Vice President and General Counsel	02/24/2011	02/24/2011	05/01/2020
Jennifer R. Hasbrouck	Senior Vice President and General Counsel	02/27/2020	05/02/2020	N/A

Quarter ending June 30, 2020:
There were no changes in officers of the respondent for quarter ending June 30, 2020.

Quarter ending September 30, 2020:

J. Christopher Thompson	Vice President	08/25/2016	10/31/2016	10/09/2020
Nicole Howard	Vice President	9/28/2020	11/12/2020	N/A

Quarter ending December 31, 2020:

Brian Barrios	Vice President	1/18/2021	02/01/2021	N/A
Larry Chung	Vice President	1/18/2021	02/16/2021	N/A

b) Changes in directors of the respondent.

Quarter ending March 31, 2020:
There were no changes in directors of the respondent for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes in directors of the respondent for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes in directors of the respondent for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes in directors of the respondent for quarter ending December 31, 2020.

c) Changes in majority security holders.

Quarter ending March 31, 2020:
There were no changes in majority security holders for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes in majority security holders for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes in majority security holders for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes in majority security holders for quarter ending December 31, 2020.

d) Changes in voting powers of the respondent.

Quarter ending March 31, 2020:
There were no changes in voting powers of the respondent for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There were no changes in voting powers of the respondent for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There were no changes in voting powers of the respondent for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There were no changes in voting powers of the respondent for quarter ending December 31, 2020.

Question 14 Cash Management Program

Quarter ending March 31, 2020:
There was no cash management program in place for quarter ending March 31, 2020.

Quarter ending June 30, 2020:
There was no cash management program in place for quarter ending June 30, 2020.

Quarter ending September 30, 2020:
There was no cash management program in place for quarter ending September 30, 2020.

Quarter ending December 31, 2020:
There was no cash management program in place for quarter ending December 31, 2020

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	04/14/2021	End of 2020/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	55,760,738,589	52,131,256,618
3	Construction Work in Progress (107)	200-201	5,032,910,818	4,131,286,128
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		60,793,649,407	56,262,542,746
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	14,781,425,486	14,137,997,599
6	Net Utility Plant (Enter Total of line 4 less 5)		46,012,223,921	42,124,545,147
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	64,463,182	65,572,514
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		184,451,158	168,909,284
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	117,511,987	105,961,809
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		131,402,353	128,519,989
14	Net Utility Plant (Enter Total of lines 6 and 13)		46,143,626,274	42,253,065,136
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		266,164,715	162,891,463
19	(Less) Accum. Prov. for Depr. and Amort. (122)		86,318,480	79,905,763
20	Investments in Associated Companies (123)		50,000	50,000
21	Investment in Subsidiary Companies (123.1)	224-225	143,655	144,181
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	2,930,127	3,439,649
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)		5,545,415,864	5,039,251,458
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		16,832,757	6,206,460
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		5,745,218,638	5,132,077,448
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,696,341	23,563,117
36	Special Deposits (132-134)		582,772	0
37	Working Fund (135)		74,525	80,375
38	Temporary Cash Investments (136)		60,800,344	14,000,158
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,042,119,325	641,296,603
41	Other Accounts Receivable (143)		365,596,779	360,887,426
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		187,758,050	49,426,661
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		34,428	3,089
45	Fuel Stock (151)	227	1,951,472	2,007,652
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	402,935,061	361,868,594
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	20,144,091	6,845,114

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		2,930,127	3,439,649
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)		280,079,123	213,194,393
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		44,295	202,801
60	Rents Receivable (172)		2,704,512	1,662,908
61	Accrued Utility Revenues (173)		520,991,998	487,658,998
62	Miscellaneous Current and Accrued Assets (174)		331,553,040	332,241,687
63	Derivative Instrument Assets (175)		107,757,699	87,417,114
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		16,832,757	6,206,460
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)		2,947,544,871	2,473,857,259
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		121,424,058	111,989,748
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	631,948	650,745
72	Other Regulatory Assets (182.3)	232	9,534,915,098	7,990,086,236
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,423,172	2,466,514
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		68,099	71,565
78	Miscellaneous Deferred Debits (186)	233	2,528,324,623	2,818,326,587
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)		132,966,470	142,053,716
82	Accumulated Deferred Income Taxes (190)	234	3,988,709,871	2,374,522,295
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		16,310,463,339	13,440,167,406
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		71,146,853,122	63,299,167,249

Schedule Page: 110   Line No.: 2   Column: c

Effective 1/1/19, SCE adopted Accounting Standards Updates requiring lessees to recognize leases on the balance sheet as right-of-use assets and related lease liabilities. SCE has elected to report these leases in the FERC balance sheet using accounts established for capital leases.

For Utility Plant (Account 101.1), the reported right-of-use assets of $1,119,661,082 includes $1,084,940,623 operating leases, $3,561,152 capital leases and $31,159,307 power purchase financing agreements.

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	04/14/2021	end of 2020/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	2,168,054,319	2,168,054,319
3	Preferred Stock Issued (204)	250-251	1,945,050,000	2,245,054,950
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	923,708
7	Other Paid-In Capital (208-211)	253	5,432,335,845	3,991,720,518
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	45,647,715	53,195,017
11	Retained Earnings (215, 215.1, 216)	118-119	9,194,082,760	9,516,129,553
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,605,695	-2,605,169
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)	-40,791,862	-38,811,870
16	Total Proprietary Capital (lines 2 through 15)		18,650,477,069	17,827,270,409
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	17,594,757,143	15,023,328,571
19	(Less) Reaquired Bonds (222)	256-257	616,900,000	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	306,345,473	306,419,792
22	Unamortized Premium on Long-Term Debt (225)		97,039,200	51,134,222
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		61,063,212	64,556,810
24	Total Long-Term Debt (lines 18 through 23)		17,320,178,604	15,316,325,775
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		902,749,630	649,512,988
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,836,509,467	2,956,425,360
29	Accumulated Provision for Pensions and Benefits (228.3)		144,366,884	236,578,606
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		0	7,216
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,929,712,156	3,028,944,766
35	Total Other Noncurrent Liabilities (lines 26 through 34)		7,813,338,137	6,871,468,936
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		2,592,655,011	549,711,893
38	Accounts Payable (232)		1,955,988,298	1,726,422,223
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		7,429,455	33,110,777
41	Customer Deposits (235)		243,014,731	301,990,939
42	Taxes Accrued (236)	262-263	99,421,750	36,992,884
43	Interest Accrued (237)		266,159,016	241,028,308
44	Dividends Declared (238)		12,705,748	213,378,635
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	04/14/2021	end of 2020/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)		24,357,196	21,375,244
48	Miscellaneous Current and Accrued Liabilities (242)		823,821,944	732,482,809
49	Obligations Under Capital Leases-Current (243)		216,911,452	82,935,485
50	Derivative Instrument Liabilities (244)		25,829	799,952
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	7,216
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)		6,242,490,430	3,940,221,933
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		191,085,209	181,075,863
57	Accumulated Deferred Investment Tax Credits (255)	266-267	61,370,919	66,459,419
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	2,363,206,764	2,617,087,758
60	Other Regulatory Liabilities (254)	278	7,728,128,616	7,626,338,812
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)		8,671,358,411	8,051,972,613
64	Accum. Deferred Income Taxes-Other (283)		2,105,218,963	800,945,731
65	Total Deferred Credits (lines 56 through 64)		21,120,368,882	19,343,880,196
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		71,146,853,122	63,299,167,249

Schedule Page: 112 Line No.: 26 Column: c

For Obligations under capital lease-noncurrent (Account 227), the reported ($902,749,630) is composed of ($870,939,858) operating leases, ($3,445,263) capital leases and ($28,364,509) power purchase financing agreements.

Schedule Page: 112 Line No.: 28 Column: c

For Accumulated Provision for Injuries and Damages (Account 228.2), the reported $3.8 billion includes $4.5 billion of liabilities for wildfire-related claims plus $0.1 billion from injuries and damages, net of $0.8 billion of insurance receivables. $0.3 billion of that receivable is due from an associated (affiliated) company.

Schedule Page: 112 Line No.: 49 Column: c

For Obligations under capital lease-current (Account 243), the reported ($216,911,452) is composed of ($214,000,764) operating leases, ($115,889) capital lease and ($2,794,799) power purchase financing 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	04/14/2021	End of 2020/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	12,734,424,572	11,755,485,033		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	9,565,559,885	7,891,735,265		
5	Maintenance Expenses (402)	320-323	1,059,124,113	826,661,209		
6	Depreciation Expense (403)	336-337	1,787,489,548	1,604,737,240		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	235,401,364	205,240,600		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,797	18,759		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		649,697	12,812,991,094		
13	(Less) Regulatory Credits (407.4)		1,465,457,859	13,954,543,330		
14	Taxes Other Than Income Taxes (408.1)	262-263	438,187,644	393,332,659		
15	Income Taxes - Federal (409.1)	262-263	-5,765,326	19,510,288		
16	- Other (409.1)	262-263	-18,280,729	18,543,761		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	3,764,488,546	3,478,214,363		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,033,626,672	3,701,070,520		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,088,500	-4,864,702		
20	(Less) Gains from Disp. of Utility Plant (411.6)			2,470		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)			33		
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)		11,322,700,508	9,590,504,183		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,411,724,064	2,164,980,850		

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
12,727,507,961	11,749,191,844	2,291,947	2,663,735	4,624,664	3,629,454	2
						3
9,555,900,911	7,887,115,767	1,984,167	1,678,379	7,674,807	2,941,119	4
1,056,452,840	824,710,212	968,958	827,735	1,702,315	1,123,262	5
1,786,243,338	1,603,165,629	264,562	258,584	981,648	1,313,027	6
						7
235,401,364	205,240,600					8
						9
18,797	18,759					10
						11
	12,812,785,236	224,562	205,858	425,135		12
1,465,457,859	13,954,321,488				221,842	13
437,935,998	393,118,813	54,480	54,588	197,166	159,258	14
-3,464,265	19,999,124	-300,396	-42,248	-2,000,665	-446,588	15
-17,347,770	18,725,811	-135,568	-21,248	-797,391	-160,802	16
3,762,319,954	3,477,128,504	381,385	226,450	1,787,207	859,409	17
4,032,392,534	3,700,016,793	317,440	285,197	916,698	768,530	18
-5,088,500	-4,864,702					19
	2,470					20
						21
	33					22
						23
						24
11,310,522,274	9,582,802,969	3,124,710	2,902,901	9,053,524	4,798,313	25
1,416,985,687	2,166,388,875	-832,763	-239,166	-4,428,860	-1,168,859	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	04/14/2021	End of 2020/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)		1,411,724,064	2,164,980,850		
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)		63,114,522	61,479,128		
34	(Less) Expenses of Nonutility Operations (417.1)		46,013,549	40,232,052		
35	Nonoperating Rental Income (418)		916,178	499,339		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-526	-1,061		
37	Interest and Dividend Income (419)		20,744,330	37,323,240		
38	Allowance for Other Funds Used During Construction (419.1)		121,067,722	101,213,751		
39	Miscellaneous Nonoperating Income (421)		27,437,963	12,224,452		
40	Gain on Disposition of Property (421.1)		720,317	4,197,447		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		187,986,957	176,704,244		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		74,244	80,937		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		22,074,758	23,023,310		
46	Life Insurance (426.2)		-36,826,418	-39,143,582		
47	Penalties (426.3)		5,091,265	-503,557		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		19,856,902	23,233,684		
49	Other Deductions (426.5)		-182,344,792	96,812,722		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-172,074,041	103,503,514		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	5,156,325	4,411,056		
53	Income Taxes-Federal (409.2)	262-263	15,740,752	-22,121,747		
54	Income Taxes-Other (409.2)	262-263	5,724,391	-9,353,568		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	34,148,103	117,546,773		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	28,011,489	129,362,526		
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)		32,758,082	-38,880,012		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		327,302,916	112,080,742		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		721,798,639	629,079,672		
63	Amort. of Debt Disc. and Expense (428)		18,945,895	15,209,740		
64	Amortization of Loss on Reaquired Debt (428.1)		12,677,630	12,446,072		
65	(Less) Amort. of Premium on Debt-Credit (429)		5,088,559	1,197,123		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		101,228,272	154,679,222		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		52,920,336	62,867,720		
70	Net Interest Charges (Total of lines 62 thru 69)		796,641,541	747,349,863		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		942,385,439	1,529,711,729		
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)		942,385,439	1,529,711,729		

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

426.5 - Includes $(150,166,900) gain on sale of nuclear fuel from SONGS, and $(40,031,316) amortization of SPIDA - pole disallowance due to the 2018 GRC decision received in 2019.

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

426.5 - Includes impairment loss $170,559,998 recorded in 2019 related to disallowed historical capital expenditures in SCE's 2018 GRC decision, and $(80,062,632) amortization of SPIDA - Pole disallowance due to the 2018 GRC decision received in 2019.

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	04/14/2021	End of 2020/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		9,324,517,212	8,525,815,448
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Adoption of Accounting Change ASU 2018-02	219		5,023,243
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			5,023,243
10	Stock-based Compensation (no tax portion)	131	-4,214	(15,107,674)
11	Redemption of Preference and Preferred Stocks:(no tax impact)			
12	Capital Stock Expense	214	-7,547,302	
13	Premium on Capital Stock	207	923,708	
14	Loss on Redemption of Preference & Preferred Shares	131	-8,611,362	
15	TOTAL Debits to Retained Earnings (Acct. 439)		-15,239,170	(15,107,674)
16	Balance Transferred from Income (Account 433 less Account 418.1)		942,385,965	1,529,712,790
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriations of Retained Earnings			
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred and Preference Stock Dividends		-117,193,589	(120,926,595)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-117,193,589	(120,926,595)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends		-1,132,000,000	(600,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-1,132,000,000	(600,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		9,002,470,418	9,324,517,212
	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	04/14/2021	End of 2020/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)		191,612,342	191,612,342
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		191,612,342	191,612,342
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		9,194,082,760	9,516,129,554
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,605,169	(2,604,107)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-526	(1,062)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-2,605,695	(2,605,169)

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

SCE received approval from FERC (docket AC19-19) for authorization to use account 439 to record the cumulative stranded tax effect adjustment to retained earnings for SCE's adoption of the SU 2018-02 "Income Statement -Reporting Comprehensive Income (Topic 220) Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income".

Schedule Page: 118 Line No.: 11 Column: c

SCE redeemed preference stock and preferred stock during 3rd quarter 2020. Loss on redemption was recorded in account 439.

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

Preferred and Preference Stock Dividends
Year-to-Date DEC. 31, 2020

	Dividend
Preferred Stock -	
4.08% Series	491,725
4.24% Series	943,400
4.32% Series	1,324,397
4.78% Series	1,149,317
Preference Stock -	
6.250% Series E	21,875,000
5.100% Series G	18,028,500
5.750% Series H	15,812,500
5.375% Series J	17,468,750
5.450% Series K	16,350,000
5.000% Series L	23,750,000
Total Dividends	$ 117,193,589

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	04/14/2021	End of 2020/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)	942,385,439	1,529,711,729
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	2,022,909,709	1,809,996,599
5	Amort. of Nuc. Fuel, Loss on Reacq. Debt, Prem. & Disc. of L/T Debt	60,673,515	71,715,502
6			
7			
8	Deferred Income Taxes (Net)	-263,001,512	-234,671,911
9	Investment Tax Credit Adjustment (Net)	-5,088,500	-4,864,703
10	Net (Increase) Decrease in Receivables	-290,008,831	-88,575,857
11	Net (Increase) Decrease in Inventory	-42,895,341	-83,288,926
12	Net (Increase) Decrease in Allowances Inventory	-13,298,976	7,267,671
13	Net Increase (Decrease) in Payables and Accrued Expenses	145,406,681	347,381,610
14	Net (Increase) Decrease in Other Regulatory Assets	-1,434,600,568	-404,449,833
15	Net Increase (Decrease) in Other Regulatory Liabilities	-392,493,822	-882,842,539
16	(Less) Allowance for Other Funds Used During Construction	121,067,722	101,213,751
17	(Less) Undistributed Earnings from Subsidiary Companies	-526	-1,061
18	Other (provide details in footnote):		
19	Prepaid and Accrued Taxes	141,351,425	178,127,776
20	Nuclear decommissioning trusts	-197,116,142	-106,315,455
21	Other - Net	873,781,670	-2,129,294,135
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,426,937,551	-91,315,162
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-4,696,474,317	-4,210,304,388
27	Gross Additions to Nuclear Fuel	-33,688,136	-39,713,280
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-42,492,950	-14,223,824
30	(Less) Allowance for Other Funds Used During Construction	-121,067,722	-101,213,751
31	Other (provide details in footnote):		
32	Cost of Removal, Salvage Value and Others	-828,544,587	-712,552,876
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-5,480,132,268	-4,875,580,617
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	168,614,359	48,566,341
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		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Proceeds from Sale of Nuclear Decommissioning Trust Investments	5,927,059,315	4,389,631,837
54	Purchases of Nuclear Decommissioning Trust Investments	-5,729,950,553	-4,283,494,342
55	Other Investments	29,499,093	36,482,206
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-5,084,910,054	-4,684,394,575
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	2,700,966,000	2,328,355,000
62	Preferred Stock		
63	Common Stock		
64	Other: Capital contribution from Edison International Parent	1,432,000,000	3,250,000,000
65	Short-Term Debt Borrowing	2,193,750,000	750,000,000
66	Net Increase in Short-Term Debt (c)	175,020,515	
67	Other (provide details in footnote):		
68	Refundable Customer Advance for Construction	10,005,379	6,914,789
69	Proceeds from Stock Option Exercises		21,864,586
70	Cash Provided by Outside Sources (Total 61 thru 69)	6,511,741,894	6,357,134,375
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-698,878,524	-81,972,549
74	Preferred Stock	-308,616,312	
75	Common Stock		
76	Other: Short-Term Debt Repayment and Long-Term Debt Issuance Cost	-350,530,000	-772,100,000
77	Shares Purchased for Stock-based Compensation	-4,950,519	-39,590,767
78	Net Decrease in Short-Term Debt (c)		-171,286,018
79	Dividends on Preference Stock	-113,667,252	-115,656,253
80	Dividends on Preferred Stock	-4,199,224	-5,270,342
81	Dividends on Common Stock	-1,332,000,000	-400,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	3,698,900,063	4,771,258,446
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	40,927,560	-4,451,291
87			
88	Cash and Cash Equivalents at Beginning of Period	37,643,650	42,094,941
89			
90	Cash and Cash Equivalents at End of period	78,571,210	37,643,650

Schedule Page: 120 Line No.: 21 Column: b

Includes wildfire related insurance receivable of $0.9 billion.

Schedule Page: 120 Line No.: 21 Column: c

Includes contributions to Wildfire Insurance Fund of $(2.5) billion.

Schedule Page: 120 Line No.: 73 Column: b

Includes long-term debt repurchase of $(617) million.

Schedule Page: 120 Line No.: 74 Column: b

Includes redemptions of preference stock ($180 million) and preferred stock ($128 million).

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.

2017/2018 Wildfire/Mudslide Events	the Thomas Fire, the Koenigstein Fire, the Montecito Mudslides and the Woolsey Fire, collectively
2019/2020 Wildfires	wildfires that originated in Southern California in 2019 and 2020 where SCE's equipment may be alleged to be associated with the fire's ignition
AB 1054	California Assembly Bill 1054, executed by the governor of California on July 12, 2019
AB 1054 Excluded Capital Expenditures	approximately $1.6 billion in wildfire risk mitigation capital expenditures that SCE will exclude from the equity portion of SCE's rate base as required under AB 1054
AB 1054 Liability Cap	a cap on the aggregate requirement to reimburse the Wildfire Insurance Fund over a trailing three calendar year period which applies if certain conditions are met and is equal to 20% of the equity portion of the utility's transmission and distribution rate base in the year of the applicable prudency determination
ARO(s)	asset retirement obligation(s)
CAISO	California Independent System Operator
Capital Structure Compliance Period	January 1, 2020 to December 31, 2022, the current compliance period for SCE's CPUC authorized capital structure
CEMA	Catastrophic Event Memorandum Accounts
COVID-19	Coronavirus disease 2019
CPUC	California Public Utilities Commission
ERRA	Energy Resource Recovery Account
FERC	Federal Energy Regulatory Commission
FERC 2019 Settlement Period	November 12, 2019 through at least December 31, 2021
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GRC	general rate case

GS&RP	Grid Safety and Resiliency Program
Koenigstein Fire	a wind-driven fire that originated near Koenigstein Road in the City of Santa Paula in Ventura County, California, on December 4, 2017
Montecito Mudslides	the debris flows and flooding in Montecito, Santa Barbara County, California, that occurred in January 2018
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
PSPS	Public Safety Power Shutoffs
ROE	return on common equity
San Onofre	retired nuclear generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
SCE	Southern California Edison Company, a wholly-owned subsidiary of Edison International
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
Tax Reform	Tax Cuts and Jobs Act signed into law on December 22, 2017
Thomas Fire	a wind-driven fire that originated in the Anlauf Canyon area of Ventura County, California, on December 4, 2017
TKM	collectively, the Thomas Fire, the Koenigstein Fire and the Montecito Mudslides
TKM Subrogation Plaintiffs	the plaintiffs party to the TKM Subrogation Settlement, representing all the insurance subrogation plaintiffs in the TKM litigation
TKM Subrogation Settlement	a settlement entered into by Edison International and SCE in September 2020 in the TKM litigation to which the TKM Subrogation Plaintiffs are party
VCFD	Ventura County Fire Department

WEMA	Wildfire Expense Memorandum Account
WMP	a wildfire mitigation plan required to be filed at least once every three years under AB 1054 to describe a utility's plans to construct, operate, and maintain electrical lines and equipment that will help minimize the risk of catastrophic wildfires caused by such electrical lines and equipment
Wildfire Insurance Fund	the insurance fund established under AB 1054
Woolsey Fire	a wind-driven fire that originated in Ventura County in November 2018
Woolsey Subrogation Plaintiffs	the plaintiffs party to the Woolsey Subrogation Settlement, representing all the insurance subrogation plaintiffs in the Woolsey Fire litigation at the time of the settlement
Woolsey Subrogation Settlement	a settlement entered into by Edison International and SCE in January 2021 in the Woolsey litigation to which the Woolsey Subrogation Plaintiffs are party
WSD	Wildfire Safety Division of the CPUC

ITEM 1. NOTES TO FINANCIAL STATEMENTS

Summary of Significant Accounting Policies

Organization and Basis of Presentation

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 financial statements include the accounts of SCE and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the financial statements.

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 service, plus a return on net investments in assets, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of electric utility revenue, these principles require an incurred cost that would otherwise be charged to expense by a non-regulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely the principles require recording 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 and refundable to customers. SCE assesses, 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 in incurred cost as allowable for rate-making purposes.

The financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published releases, which is a comprehensive basis of accounting other than generally accepted accounting principles, that requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates.

The notes below are excerpts from SCE's Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission ("SEC") on February 25, 2021, and include specific information requested by the FERC. See SCE's Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2020 for financial statements and complete footnotes prepared in accordance with accounting principles generally accepted in the United States of America. Subsequent events were evaluated through the date the FERC Form 1 report was filed. 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 (FERC account 123.1) rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries which is required by GAAP, except for Edison Material Supply LLC. Due to the nature of the business, SCE consolidates Edison Material Supply LLC. 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. In April 2018, the Commission approved the requested the use of equity method of accounting waiver for Edison Material Supply LLC (Docket No. AC18-56-000).

Asset Retirement Obligation ("ARO")

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 (FERC accounts 108 and 119).

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 (FERC account 128), a noncurrent asset. For GAAP reporting purposes, this asset is classified as a miscellaneous deferred debit, which is also a noncurrent asset. In addition, for FERC reporting purposes, all components of net periodic benefit costs are recorded as operation expenses (FERC account 926). In accordance with FERC guidance, SCE has made an accounting policy election to utilize only the service cost component of net periodic benefit costs for purposes of overhead capitalization. GAAP presents service costs as operating expense and non-service costs within other income and expenses, and also limits the capitalization of benefit costs to the service cost component.

Debt Issuance Costs

For FERC reporting purposes, debt issuance costs are classified as unamortized debt expense and reflected as an asset (FERC account 181) on the FERC balance sheet. For GAAP reporting purposes, long-term debt issuance costs are classified as a reduction of the debt balance.

Wildfire Insurance Fund

For FERC reporting purposes, contribution to Wildfire Insurance Fund are presented as miscellaneous current and accrued asset (FERC account 174) and miscellaneous deferred debits (FERC account 186). Unpaid contribution to Wildfire Insurance Fund are presented as miscellaneous current and accrued liabilities (FERC account 242) and other deferred credits (FERC account 253). For GAAP reporting purposes, contributions to Wildfire Insurance Fund are reflected as Wildfire Insurance Fund contributions and unpaid contributions to Wildfire Insurance Fund are reflected as other current liabilities and other deferred credits and other long-term liabilities.

Liabilities for wildfire-related claims

For FERC reporting purposes, liabilities for wildfire-related claims are presented net of insurance receivables (FERC account 228.2). For GAAP reporting purposes, insurance receivables are reflected as an asset.

Leases

For FERC reporting purposes, operating leases are reported in utility plant (FERC account 101.1), with corresponding lease obligations reported in obligations under capital leases (FERC accounts 227 and 243). These operating leases are reported in operating lease right-of-use ("ROU") assets and operating lease liabilities on the GAAP balance sheet. In addition, the expense of capital leases, which relate to power purchase agreements, are recorded as power purchase expense (FERC account 555) for FERC reporting purposes and reflected as depreciation and interest expense for GAAP reporting purposes. Effective January 1, 2019, SCE adopted accounting standard updates in relation to leases using the modified retrospective approach.

Other Differences

For FERC reporting purposes current maturities of long-term debt are included as part of long-term debt (FERC account 221), 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 reporting classifies all regulatory assets (FERC accounts 182.2 and 182.3) and liabilities (FERC account 254) as noncurrent. Retained earnings are presented differently under the Uniform System of Accounts for FERC purposes than for GAAP purposes.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents include investments in money market funds. Generally, the carrying value of cash equivalents equals the fair value, as these investments have original maturities of three months or less. The cash equivalents were $38 million at December 31, 2020. There were no cash equivalents at December 31, 2019. Cash is temporarily invested until required for check clearing. Checks issued, but not yet paid by the financial institution, were reclassified from cash to accounts payable in the amounts of $69 million and $74 million at December 31, 2020 and 2019, respectively.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is recorded based on SCE's estimate of expected credit losses and adjusted over the life of the receivables as needed. Since the customer base of SCE is concentrated in Southern California and exposes SCE to a homogeneous set of economic conditions, the allowance is measured on a collective basis on the historical amounts written-off, assessment of customer collectibility and current economic trends, including unemployment rates and any likelihood of recession for the region. At December 31, 2020, this included the estimated impacts of the COVID-19 pandemic.

The following table sets forth the changes in allowance for uncollectible accounts (FERC account 144) for SCE:

	Year ended December 31, 2020	
(in millions)	Customers	All others
Beginning balance	$ 35	$ 14
Plus: current period provision for uncollectible accounts		
Included in operation and maintenance expenses	36	9
Deferred to regulatory assets	120	—
Less: write-offs, net of recoveries	16	10
Ending balance	$ 175	$ 13

Inventory

SCE's inventory is primarily composed of materials, supplies and spare parts, and generally stated at weighted average cost.

Emission Allowances and Energy Credits

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 (FERC account 158.1).

SCE is allocated low carbon fuel standard ("LCFS") credits which it sells to market participants. Proceeds from the sales, net of program costs, are recorded in a balancing account to be refunded to eligible customers.

Property, Plant and Equipment

SCE plant additions, including replacements and betterments, are capitalized. Direct material and labor and indirect costs such as construction overhead, administrative and general costs, pension and benefits, and property taxes are capitalized as part of plant additions. The California Public Utilities Commission ("CPUC") authorizes a capitalization 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 $121 million, $101 million and $104 million in 2020, 2019 and 2018, respectively. AFUDC debt was $53 million, $63 million and $44 million in 2020, 2019 and 2018, respectively

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 California Independent System Operator ("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 $562 million and $502 million would have been capitalized as of December 31, 2020 and 2019, respectively. The following is a partial balance sheet that includes the amounts not capitalized because of the transmission rate incentives.

(in millions)	December 31, 2020	December 31, 2019
Utility property, plant and equipment	$ 56,185	$ 52,552
Construction work in progress	5,170	4,213
Total utility property plant and equipment	61,355	56,765
(Less) accumulated provision for depreciation, amortization and depletion	(14,847)	(14,194)
Net utility property, plant and equipment	$ 46,508	$ 42,571

Estimated useful lives authorized by the CPUC in the 2018 General Rate Case ("GRC") 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 55 years	36 years
Distribution plant	20 years to 65 years	48 years
Transmission plant	45 years to 65 years	54 years
General plant and other	5 years to 60 years	25 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. SCE's depreciation expense was $1.8 billion, $1.7 billion and $1.7 billion for 2020, 2019 and 2018, respectively. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 3.6%, 3.6% and 3.7% for 2020, 2019 and 2018, respectively. The original costs of retired property are charged to accumulated depreciation.

Nuclear fuel for the Palo Verde Nuclear Generating Station ("Palo Verde") 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. Palo Verde 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.

Energy Storage Assets

At December 31, 2020, SCE's energy storage assets totaled $66 million. The following table summarizes the operations associated with these energy storage assets for the year ended December 31, 2020:

Name of the Energy Storage Project	Mira Loma Unit A	Mira Loma Unit B	Center Peaker [6]	Grapeland Peaker [6]	Camden [8]	Del Sur [8]	Total [7]
Functional Classification	Production	Production	Production	Production	Distribution	Distribution	
Location of the Project	Ontario, CA	Ontario, CA	Norwalk, CA	Rancho Cucamonga, CA	Santa Ana, CA	Antelope Valley, CA	
Megawatt hours (MWHs) [1]	9,226	9,240	975	820	332	819	21,411
MWHs delivered to the grid to support production, transmission and distribution [2]	8,045	8,059	655	611	290	685	18,345
MWHs lost during conversion, storage and discharge of energy [2]	1,205	1,206	320	209	41	133	3,114
MWHs sold	6,190	6,032	-	-	-	-	12,222
Revenues from energy storage operations	356,916	403,312	-	-	-	-	760,229
Power purchased for storage operations (555.1) [3,7]	119,844	146,205	-	-	-	-	266,050
Other costs associated with self-generated power [4]	314,363	132,164	87,952	85,146	-	-	619,625
Project costs [2,5]	16,012,932	15,957,155	9,935,141	9,810,871	6,897,938	7,276,401	65,890,438

1. Represents megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
2. Relates to production functional and distribution use as there were no transmission-related energy storage assets at December 31, 2020.
3. Total power purchased for storage operations were recorded in the existing purchased power account 555, which would have been reported in account 555.1 if the FERC system permitted.
4. Other costs associated with energy storage plants were recorded in the existing maintenance of generating and electric plant account 553, which would have been reported in account 553.1 if the FERC system permitted.
5. The project costs were included in accounts 101 and 106 and were reported in the existing functional plant account 346, which would have been reported in energy storage account 348 if the FERC system permitted.
6. Relates to energy storage assets, which are located at sites that have both battery and gas turbine operations. For the year ended December 31, 2020, SCE sold 17,891 MWH and 16,570 MWH and recognized revenue of $2,406,944 and $1,857,290 from the battery and gas turbine operations at the Center Peaker and Grapeland Peaker sites, respectively.
7. The fuel costs for the Center Peaker and Grapeland Peaker were excluded from the table above as the fuel costs for these energy storage assets are disclosed in the Steam-Electric Generating Plant Statistics Page (See 402-403a, line 20 for details).
8. The Camden and Del Sur substations are energy storage systems which are connected to the Titanium and Pronghorn circuits. These systems have not yet connected to the CAISO market.

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.

Accounting principles for rate-regulated enterprises also require recognition of an impairment loss if it becomes probable that the regulated utility will abandon a plant investment, or if it becomes probable that the cost of a recently completed plant will be disallowed, either directly or indirectly, for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made.

Initial and annual contributions to the wildfire insurance fund established pursuant to California Assembly Bill 1054 (the "Wildfire Insurance Fund" and "AB 1054")

SCE accounted for the contributions to the Wildfire Insurance Fund similarly to prepaid insurance. No period of coverage was provided in AB 1054, therefore expense is being allocated to periods ratably based on an estimated period of coverage. SCE has a $2.4 billion and $2.8 billion long-term asset at December 31, 2020 and December 31, 2019, respectively, and a $323 million current asset reflected as miscellaneous deferred debits (FERC account 186) and miscellaneous current and accrued assets (FERC account 174), respectively for the initial $2.4 billion contribution made during the third quarter of 2019 and the present value of annual contributions SCE committed to make to the Wildfire Insurance Fund, reduced by amortization at both December 31, 2020 and December 31, 2019. A long-term liability of $703 million and $785 million have been reflected in other deferred credits (FERC account 253) for the present value of unpaid contribution amounts at December 31, 2020 and December 31, 2019, respectively. Contributions were discounted to the present value at the date SCE committed to participate in the Wildfire Insurance Fund using US treasury interest rates.

During 2020 a period of 10 years was used to amortize the asset. All expenses related to the contributions are being reflected in operation expenses (FERC account 548) in SCE's statement of income. Changes in the estimated period of coverage provided by the Wildfire Insurance Fund could lead to material changes in future expense recognition. In estimating the period of coverage SCE used *Monte Carlo* simulations based on five years (2014 – 2018) of historical data from wildfires caused by electrical utility equipment to estimate expected losses. The details of the operation of the Wildfire Insurance Fund and estimates related to claims by SCE, Pacific Gas & Electric Company ("PG&E") and San Diego Gas & Electric ("SDG&E") against the fund have been applied to the expected loss simulations to estimate the period of coverage of the fund. The most sensitive inputs to the estimated period of coverage are the expected frequency of wildfire events caused by investor-owned utility electrical equipment and the estimated costs associated with those forecasted events. SCE evaluates all inputs annually, or upon claims being made from the fund for catastrophic wildfires, and the expected life of the insurance fund will be adjusted as required. Based on information available in the first quarter of 2021 regarding catastrophic wildfires during 2019 and 2020, SCE reassessed its estimate of the life of the Wildfire Insurance Fund. Using 7 years of historical data (2014 – 2020) of wildfires caused by electrical utility equipment to create *Monte Carlo* simulations of expected loss, resulted in the expected life of the Wildfire Insurance Fund increasing from 10 years to 15 years from the date SCE committed to participate in the Wildfire Insurance Fund.

SCE will assess the Wildfire Insurance Fund contribution assets for impairment in the event that a participating utility's electrical equipment is found to be the substantial cause of a catastrophic wildfire, based on the ability of SCE to benefit from the coverage provided by the Wildfire Insurance Fund in an amount equal to the recorded assets.

Nuclear Decommissioning and 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.

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

The following table summarizes the changes in SCE's ARO liability:

	December 31,	
(in millions)	2020	2019
Beginning balance	$ 3,029	$ 3,031
Accretion[1]	160	166
Revisions	(36)	4
Liabilities settled	(223)	(172)
Ending balance	$ 2,930	$ 3,029

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.

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.

The ARO for decommissioning SCE's San Onofre Nuclear Generating Station ("San Onofre") and Palo Verde nuclear power facilities is $2.6 billion as of December 31, 2020. The liability to decommission SCE's nuclear power facilities is based on a 2017 decommissioning study that was filed as part of the 2018 NDCTP for San Onofre Units 1, 2 and 3, and a 2019 decommissioning study for Palo Verde. SCE revised the ARO for Palo Verde in 2020 and for San Onofre Units 1, 2 and 3 in 2018 to reflect updated decommissioning cost estimates.

SCE 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.

Decommissioning of San Onofre Unit 1 began in 1999 and the transfer of spent nuclear fuel from Unit 1 to dry cask storage in the Independent Spent Fuel Storage Installation ("ISFSI") was completed in 2005. Major decommissioning work for Unit 1 has been completed except for certain underground work. Decommissioning of San Onofre Units 2 and 3 began in June 2013 and the spent nuclear fuel transfer from San Onofre Units 2 and 3 to dry cask storage in the ISFSI was completed in August 2020. In October 2019, the California Coastal Commission approved SCE's application for the Coastal Development Permit, the principal discretionary permit required to start major decommissioning activities at San Onofre. In August 2020, SCE commenced major decommissioning activities at San Onofre in accordance with the terms of the permit.

Decommissioning costs, which are recovered through 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. Due to regulatory recovery of SCE's nuclear decommissioning expense, prudently incurred costs for nuclear decommissioning activities do not affect SCE's earnings. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are deferred as decreases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future decommissioning of its nuclear assets and has placed those amounts in independent trusts. Amounts collected in rates in excess of the ARO liability 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 $6.6 billion through 2079 to decommission its nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 0.6% to 7.5% (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 1.3% to 4.1% dependent on asset class. If the assumed return on trust assets is not earned or costs escalate at higher rates, SCE expects that additional funds needed for decommissioning will be recoverable through future rates, subject to a reasonableness review.

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 triennial regulatory proceeding. SCE's nuclear decommissioning trust investments primarily consist of fixed income investments that are classified as available-for-sale and equity investments. Due to regulatory mechanisms, investment earnings and realized gains and losses have no impact on earnings. Unrealized gains and losses on decommissioning trust funds, including impairment, 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 fixed income security for impairment on the last day of each month. If the fair value on the last day of the month is less than the amortized cost for that security, SCE impairs the disclosed amortized cost. If the fair value is greater or less than the carrying value for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

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 $133 million and $142 million at December 31, 2020 and 2019, respectively (FERC account 189). In addition, SCE had debt issuance costs related to issuances of long-term debt of $117 million and $106 million at December 31, 2020 and December 31, 2019, respectively (FERC account 181).

Amortization of deferred financing costs charged to interest expense was $27 million, $26 million and $26 million for 2020, 2019, and 2018, respectively.

Revenue Recognition

Revenue is recognized by SCE when a performance obligation to transfer control of the promised goods is satisfied or when services are rendered to customers. This typically occurs when electricity is delivered to customers, which includes amounts for services rendered but unbilled at the end of a reporting period.

SCE's Revenue from Contracts with Customers

Provision of Electricity

SCE principally generates revenue through supplying and delivering electricity to its customers. Rates charged to customers are based on tariff rates, approved by the CPUC and FERC. Starting with SCE's 2021 GRC, CPUC revenue will be authorized through quadrennial GRC proceedings, which are intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its CPUC-jurisdictional rate base. The CPUC sets an annual revenue requirement for the base year and the remaining three years are set by a methodology established in the GRC proceeding. Revenue was previously authorized by the CPUC in triennial GRC proceedings. As described above, SCE also earns revenue, with no return, to recover costs for power procurement and other activities.

FERC-authorized revenue is determined through a formula rate which is intended to provide SCE a reasonable opportunity to recover transmission capital and operating costs that are prudently incurred, including a return on its FERC-jurisdictional rate base. Under the operation of the formula rate, transmission revenue is updated to actual cost of service annually.

For SCE's electricity sales for both residential and non-residential customers, SCE satisfies the performance obligation of delivering electricity over time as the customers simultaneously receive and consume the delivered electricity.

Energy sales are typically on a month-to-month implied contract for transmission, distribution and generation services. Revenue is recognized over time as the energy is supplied and delivered to customers and the respective revenue is billed and paid on a monthly basis.

CPUC and FERC rates decouple authorized revenue from the volume of electricity sales and the price of energy procured so that SCE receives revenue equal to amounts authorized by the relevant regulatory agencies. As a result, the volume of electricity sold to customers and specific customer classes does not have a direct impact on SCE's financial results.

Sales and Use Taxes

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. SCE's franchise fees billed to customers were $131 million, $122 million and $133 million for the years ended December 31, 2020, 2019 and 2018, respectively. When SCE acts as an agent for sales and use tax, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are remitted to the taxing authorities and are not recognized as electric utility revenue.

SCE's Alternative Revenue Programs

The CPUC and FERC have authorized additional, alternative revenue programs which adjust billings for the effects of broad external factors or compensate SCE for demand-side management initiatives and provide for incentive awards if SCE achieves certain objectives. These alternative revenue programs allow SCE to recover costs that SCE has been authorized to pass on to customers, including costs to purchase electricity and natural gas, and to fund public purpose, demand response, and customer energy efficiency programs. In general, revenue is recognized for these alternative revenue programs at the time the costs are incurred and, for incentive-based programs, at the time the awards are approved by the CPUC. SCE begins recognizing revenues for these programs when a program has been established by an order from either the CPUC or FERC that allows for automatic adjustment of future rates, the amount of revenue for the period is objectively determinable and probable of recovery and the revenue will be collected within 24 months following the end of the annual period.

The following table is a summary of SCE's revenue:

	Years ended December 31,		
(in millions)	2020	2019	2018
Revenues from contracts with customers[1,2]	$ 12,459	$ 11,167	12,130
Alternative revenue programs and other operating revenue[3]	1,087	1,139	481
Total operating revenue	$ 13,546	$ 12,306	$ 12,611

1 In the absence of a 2018 GRC decision, SCE recognized CPUC revenue in 2018 and first quarter of 2019 based on the 2017 authorized revenue requirements adjusted mainly for the July 2017 cost of capital decision and Tax Reform. SCE recorded the impact of the 2018 GRC final decision in the second quarter of 2019, including a $289 million reduction in revenue related to 2018. These revenue adjustments are included in "Revenues from contracts with customers."

2 At December 31, 2020 and 2019, SCE's receivables related to contracts from customers were $1.5 billion and $1.1 billion, which included accrued unbilled revenue of $521 million and $488 million, respectively.

3 Includes differences between amounts billed and authorized levels for both the CPUC and FERC.

Regulatory Proceedings

2018 General Rate Case

In May 2019, the CPUC approved a final decision in SCE's 2018 GRC.

The revenue requirements in the 2018 GRC final decision are retroactive to January 1, 2018. SCE recorded the prior period impact of the 2018 GRC final decision in 2019 including:

An increase to earnings of $65 million attributable to 2018 from the application of the decision to revenue, depreciation expense and income tax expense. The reduction of revenue of $289 million reflected the lower authorized revenue related to 2018.

An impairment of utility property, plant and equipment of $170 million ($123 million after-tax) related to disallowed historical capital expenditures, primarily the write-off of specific pole replacements the CPUC determined were performed prematurely.

2021 General Rate Case

In the 2021 GRC, SCE has requested a test year revenue requirement of $7.6 billion, an approximately $1.3 billion increase over the 2020 revenue requirement authorized in the 2018 GRC as updated for post test-year ratemaking changes.

SCE has not received a proposed decision on track 1 of the 2021 GRC. The CPUC has approved the establishment of a memorandum account making the authorized revenue requirement changes effective January 1, 2021. SCE cannot predict the revenue requirement the CPUC will ultimately authorize or forecast the timing of a final decision. SCE expects to recognize revenue based on the 2020 authorized revenue requirement until a GRC decision is issued.

Power Purchase Agreements

SCE enters into power purchase agreements ("PPAs") in the normal course of business. A power purchase agreement may be considered a variable interest in a variable interest entity ("VIE"). If SCE is the primary beneficiary in the VIE, SCE should consolidate the VIE. None of SCE's PPAs resulted in consolidation of a VIE at December 31, 2020 and 2019.

A PPA may also contain a lease for accounting purposes. See "Leases" below for further discussion of SCE's PPAs, including agreements that are classified as operating and finance leases for accounting purposes.

A PPA that does not contain a lease may be classified as a derivative which is recorded at fair value on the balance sheets. These PPAs may be eligible for an election to designate as a normal purchase and sale, which is accounted for on an accrual basis as an executory contract. PPAs that do not meet the above classifications are accounted for on an accrual basis.

Derivative Instruments

SCE records derivative instruments on its 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 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 statements of cash flows.

Leases

On January 1, 2019, SCE adopted accounting standards updates that require lessees to recognize a lease on the balance sheet as a right-of-use ("ROU") asset and related lease liability and classify the lease as either operating or finance. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified assets for a period of time in exchange for consideration. An entity controls the use when it has a right to obtain substantially all of the benefits from the use of the identified asset and has the right to direct the use of the asset. SCE determines if an arrangement is a lease at contract inception. SCE includes both the lease and non-lease components as a single component and accounts for them as a lease for all classes of underlying assets, except energy storage underlying assets which were first contracted in 2020 and for which each component will be separately accounted for. Lease liabilities are recognized based on the present value of the lease payments over the lease term at the commencement date. SCE calculates and uses the rate implicit in the lease if the information is readily available or if not available, SCE uses its incremental borrowing rate in determining the present value of lease payments. Incremental borrowing rates are comprised of underlying risk-free rates and secured credit spreads relative to first mortgage bonds with like tenors of lease term durations. Lease ROU assets are based on the liability, subject to adjustments, such as lease incentives. The ROU assets also include any lease payments made at or before the commencement date. SCE excludes variable lease payments in measuring lease assets and lease liabilities, other than those that depend on an index or a rate or are in substance fixed payments. SCE's lease terms include options to extend or terminate the lease when it is reasonably certain that such options will be exercised. For FERC reporting purposes, operating leases are not required to be capitalized and would have been reported in account 548.1 if the FERC system permitted. However, SCE has elected to report operating leases in the FERC balance sheet using the accounts established for capital leases. In addition, the depreciation of capital leases and the amortization of interest expense associated with the lease obligations are not recognized under FERC. Instead, capital lease payments (for power purchase agreements only) are recorded and reflected as power purchase expense for FERC reporting purposes. Adoption of the accounting guidance had no impact on SCE's existing ratemaking treatment or FERC jurisdiction cost-of-service rates.

SCE enters into power purchase agreements that may contain leases. This occurs when a power purchase agreement designates a specific power plant, SCE obtains substantially all of the economic benefits from the use of the plant and has the right to direct the use of the plant. SCE also enters into a number of agreements to lease property and equipment in the normal course of business, primarily related to vehicles, office space and other equipment.

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. For equity awards that are settled in common stock, Edison International either issues new common stock, or uses a third party to purchase shares from the market and deliver such shares for the settlement of the awards. The performance shares granted during 2018 that are earned, have been or will be settled solely in cash. The performance shares granted in 2019 and 2020 that are earned, will be settled in common stock. Stock options, deferred stock units and restricted stock units are settled in common stock. However, for awards that are otherwise settled entirely in common stock, Edison International substitutes cash awards to the extent necessary to satisfy applicable tax withholding obligations or government levies.

Stock-based compensation expense is recognized, net of estimated forfeitures, on a straight-line basis over the requisite service period based on estimated fair values. For equity awards paid in common stock, fair value is determined at the grant date. However, with respect to the portion of the performance shares payable in common stock that are subject to market and financial performance conditions 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 to compensation expense. Awards paid in cash are classified as share-based liability awards and fair value is remeasured at each reporting date with the related compensation cost adjusted. For awards granted to retirement-eligible participants, stock compensation expense is recognized on a prorated basis over the initial year. For awards granted to participants who become eligible for retirement during the requisite service period, stock compensation expense is recognized over the period between the date of grant and the date the participant first becomes eligible for retirement. SCE estimate the number of awards that are expected to vest rather than account for forfeitures when they occur. Share-based payments may create a permanent difference between the amount of compensation expense recognized for book and tax purposes. The tax impact of this permanent difference is recognized in earnings in the period it is created.

Income Taxes

SCE estimates income taxes for each jurisdiction in which they operate. 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, which are included in the balance sheets.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest income, interest expense and penalties associated with income taxes are generally reflected in "Income tax expense" on the statement of income.

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.

Subsequent Events

In February 2021, SCE Recovery Funding LLC, a bankruptcy remote, wholly owned special purpose subsidiary of SCE, issued $338 million of Senior Secured Recovery Bonds, Series 2021-A, in three tranches of $138 million, 0.86% due 2033, $100 million, 1.94% due 2040, and $100 million, 2.51% due 2045 ("Recovery Bonds") and used the proceeds to acquire SCE's right, title and interest in and to non-bypassable rates and other charges to be collected from certain existing and future customers in SCE's service territory, associated with the AB 1054 Excluded Capital Expenditures ("Recovery Property"). The Recovery Bonds were payable only from and secured by the Recovery Property. SCE Recovery Funding LLC is considered a VIE and will be consolidated by SCE for financial reporting purposes, however, the Recovery Bonds do not constitute a debt or other legal obligation of, or interest in, SCE or any of its affiliates, except for SCE Recovery Funding LLC. SCE used the proceeds it received from the sale of Recovery Property to reimburse itself for previously incurred AB 1054 Excluded Capital Expenditures, including the retirement of related debt.

New Accounting Guidance

Accounting Guidance Adopted

In June 2016, the Financial Accounting Standards Board ("FASB") issued an accounting standards update to require the use of the current expected credit loss model to measure impairment of financial assets measured at amortized cost, including trade and other receivables, and the use of an allowance to record estimated credit losses on available-for-sale debt securities. SCE adopted this guidance on January 1, 2020 using the prospective adoption approach to available-for-sale debt securities and the modified retrospective approach to all other financial assets. The adoption of this guidance did not have a material impact on SCE's financial position or result of operations. See "Allowance for Uncollectible Accounts" and "Nuclear Decommissioning and Asset Retirement Obligations" above.

In August 2018, the FASB issued an accounting standards update which aligns the requirement for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing costs incurred to develop or obtain internal use software. The guidance also clarified presentation requirements for reporting implementation costs in the financial statements. For FERC accounting purposes these implementation costs will be accounted for as utility plant in FERC account 101 and the depreciation will be recorded to FERC account 403. SCE adopted the standard on January 1, 2020 using the prospective adoption approach. The adoption of this guidance did not have a material impact on SCE's financial position or result of operations.

In March 2020, the FASB issued an accounting standards update to provide optional expedients and exceptions for applying GAAP to contracts, hedging relationships, and other transactions that reference London Inter-Bank Offered Rate ("LIBOR") or another reference rate expected to be discontinued because of reference rate reform. In January 2021, the FASB issued an update to this standard to clarify that certain optional expedients and exceptions for contract modifications and hedge accounting apply to derivatives that are affected by the reference rate transition. SCE has adopted the standard as of April 1, 2020 prospectively. SCE generally does not use hedge accounting for derivative transactions. SCE has a term loan with a variable interest rate based on LIBOR. In addition, SCE has revolving credit facilities with a variable interest rate based on LIBOR. These agreements contain provisions that require an amendment if LIBOR can no longer be used. SCE also has certain preference stocks, for which the distributions will be payable at a floating rate referenced to LIBOR from 2022. As of December 31, 2020, SCE has not utilized any of the expedients and therefore there is no impact on adoption of the guidance, however, if contract amendments are made where LIBOR is no longer valid, SCE expects to utilize the expedients through the allowed period of December 31, 2022.

In August 2018, the FASB issued an accounting standards update to remove, modify and add certain disclosure requirements related to employer-sponsored defined benefit pension or other postretirement plans. The guidance removes disclosure requirements that are no longer considered cost beneficial, clarifies certain specific disclosure requirements and adds disclosure requirements identified as relevant. The modifications only affect annual period disclosures and must be applied on a retrospective basis to all periods presented. SCE has adopted this guidance for the year ending December 31, 2020. The adoption of this guidance did not materially affect the annual disclosures related to employer-sponsored defined benefit pension or other postretirement plans.

Accounting Guidance Not Yet Adopted

In August 2020, the FASB issued an accounting standards update to simplify the accounting for certain financial instruments with characteristics of liabilities and equity. The amendments in this update affect entities that issue convertible instruments indexed to or potentially settled in an entity's own equity. This guidance also simplifies an entity's application of the derivatives scope exception for contracts in its own equity and amends certain aspects of the EPS guidance. The guidance is effective January 1, 2022 with early adoption permitted after January 1, 2021. SCE do not expect the adoption of this standard will materially affect SCE's financial position or result of operations.

Property, Plant and Equipment

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, primarily ranging from 5 to 7 years and commencing upon operational use. Capitalized software costs, included in general plant and other above, were $1.2 billion and $1.0 billion at December 31, 2020 and 2019, respectively, and accumulated amortization was $0.6 billion and $0.4 billion, at December 31, 2020 and 2019, respectively. Amortization expense for capitalized software was $218 million, $190 million and $198 million in 2020, 2019 and 2018, respectively. At December 31, 2020, amortization expense is estimated to be $213 million, $168 million, $136 million, $82 million and $30 million for 2021 through 2025, respectively.

Jointly Owned Utility Projects

SCE owns undivided interests in transmission and generating assets for which each participant provides its own financing. SCE's proportionate share of these assets is reflected in the balance sheets and included in the above table. SCE's proportionate share of expenses for each project is reflected in the statements of income.

The following is SCE's investment in each asset as of December 31, 2020:

(in millions)	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Nuclear Fuel (at amortized cost)	Net Book Value	Ownership Interest
Transmission systems:						
Eldorado	$ 324	$ 74	$ 39	$ —	$ 359	79 %
Pacific Intertie	346	—	74	—	272	50 %
Generating station:						
Palo Verde (nuclear)	2,113	53	1,609	131	688	16 %
Total	$ 2,783	$ 127	$ 1,722	$ 131	$ 1,319	

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

Variable Interest Entities
A 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 Agreements

SCE has PPAs that are classified as variable interests in VIEs, including agreements through which SCE provides the natural gas to fuel the plants and fixed price contracts for renewable energy. 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 balance sheet that relate to involvement with VIEs result from amounts due under the PPAs. 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 5,103 megawatts ("MW") and 4,497 MW at December 31, 2020 and 2019, respectively, and the amounts that SCE paid to these projects were $744 million and $833 million for the years ended December 31, 2020 and 2019, respectively. These amounts are recoverable in customer rates, subject to reasonableness review.

Unconsolidated Trusts of SCE

SCE Trust II, Trust III, Trust IV, Trust V and Trust VI were formed in 2013, 2014, 2015, 2016 and 2017, respectively, for the exclusive purpose of issuing the 5.10%, 5.75%, 5.375%, 5.45% and 5.00% 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 II, Trust III, Trust IV, Trust V and Trust VI issued to the public trust securities in the face amounts of $400 million, $275 million, $325 million, $300 million and $475 million (cumulative, liquidation amounts of $25 per share), respectively, and $10,000 of common stock each to SCE. The trusts invested the proceeds of these trust securities in Series G, Series H, Series J, Series K and Series L Preference Stock issued by SCE in the principal amounts of $400 million, $275 million, $325 million, $300 million and $475 million (cumulative, $2,500 per share liquidation values), respectively, which have substantially the same payment terms as the respective trust securities.

The Series G, Series H, Series J, Series K and Series L Preference Stock and the corresponding trust securities do not have a maturity date. Upon any redemption of any shares of the Series G, Series H, Series J, Series K or Series L 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 if and when the SCE board of directors declares and makes dividend payments on the related Preference Stock. The applicable trust 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.

In September 2020, SCE Trust II redeemed $180 million of its trust securities from the public. The Trust II balance sheets as of December 31, 2020 and December 31, 2019 consisted of investments of $220 million and $400 million in the Series G Preference Stock, respectively, $220 million and $400 million of trust securities, respectively, and $10,000 each of common stock. The Trust III, Trust IV, Trust V and Trust VI balance sheets as of December 31, 2020 and December 31, 2019 consisted of investments of $275 million, $325 million, $300 million, and $475 million in the Series H, Series J, Series K and Series L Preference Stock, respectively, $275 million, $325 million, $300 million, and $475 million of trust securities, respectively, and $10,000 each of common stock.

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

	Years ended December 31,				
(in millions)	Trust II	Trust III	Trust IV	Trust V	Trust VI
2020					
Dividend income	$ 20	$ 16	$ 17	$ 16	$ 24
Dividend distributions	20	16	17	16	24
2019					
Dividend income	$ 20	$ 16	$ 17	$ 16	$ 24
Dividend distributions	20	16	17	16	24
2018					
Dividend income	$ 20	$ 16	$ 17	$ 16	$ 24
Dividend distributions	20	16	17	16	24

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, 2020 and 2019, 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 an exchange (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 derivative contracts that trade infrequently such as congestion revenue rights ("CRRs").

Assumptions are made in order to value derivative contracts in which observable inputs are not available. 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.

SCE

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, 2020				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ 6	$ 120	$ (18)	$ 108
Other	39	23	—	—	62
Nuclear decommissioning trusts:					
Stocks[2]	1,908	—	—	—	1,908
Fixed Income[3]	519	2,113	—	—	2,632
Short-term investments, primarily cash equivalents	447	52	—	—	499
Subtotal of nuclear decommissioning trusts[4]	2,874	2,165	—	—	5,039
Total assets	2,913	2,194	120	(18)	5,209
Liabilities at fair value					
Derivative contracts	—	10	12	(22)	—
Total liabilities	—	10	12	(22)	—

Net assets	$ 2,913	$ 2,184	$ 108	$ 4	$ 5,209

	December 31, 2019				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ 19	$ 83	$ (15)	$ 87
Other	4	14	—	—	18
Nuclear decommissioning trusts:					
Stocks[2]	1,765	—	—	—	1,765
Fixed Income[3]	738	2,024	—	—	2,762
Short-term investments, primarily cash equivalents	98	48	—	—	146
Subtotal of nuclear decommissioning trusts[4]	2,601	2,072	—	—	4,673
Total assets	2,605	2,105	83	(15)	4,778
Liabilities at fair value					
Derivative contracts	—	11	5	(15)	1
Total liabilities	—	11	5	(15)	1
Net assets	$ 2,605	$ 2,094	$ 78	$ —	$ 4,777

1 Represents the netting of assets and liabilities under master netting agreements and cash collateral.

2 Approximately 71% and 72% of SCE's equity investments were located in the United States at December 31, 2020 and 2019, respectively.

3 Includes corporate bonds, which were diversified and included collateralized mortgage obligations and other asset backed securities of $29 million and $46 million at December 31, 2020 and 2019, respectively.

4 Excludes net payables of $206 million and $111 million at December 31, 2020 and 2019, respectively, which consist of interest and dividend receivables as well as receivables and payables related to SCE's pending securities sales and purchases.

SCE 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)	2020	2019
Fair value of net assets at beginning of period	$ 78	$ 141
Purchases	8	6
Sales	(5)	(5)
Settlements	(117)	(60)
Total realized/unrealized gains (losses) [1,2]	144	(4)
Fair value of net assets at end of period	108	78

1 Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets (FERC account 182.3) and liabilities (FERC account 254).

2 There were no material transfers into or out of Level 3 during 2020 and 2019.

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	Significant Unobservable Input	Range (per MWh)	Weighted Average (per MWh)
Congestion revenue rights						
December 31, 2020	$ 120	$ 12	Auction prices	CAISO CRR auction clearing prices	$(9.67) - $300.47	$2.75
December 31, 2019	83	5	Auction prices	CAISO CRR auction clearing prices	(3.59) - 25.32	1.97

Level 3 Fair Value Uncertainty

For CRRs, increases or decreases in CAISO auction price would result in higher or lower fair value, respectively.

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. There are no securities classified as Level 3 in the nuclear decommissioning trusts.

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. The trustee monitors prices supplied by pricing services, including reviewing prices against defined parameters' tolerances and performs research and resolves variances beyond the set parameters. 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. 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, 2020		December 31, 2019	
(in millions)	Carrying Value[1]	Fair Value[2]	Carrying Value[1]	Fair Value[2]
SCE	17,204	20,365	15,211	16,892

1 Carrying value is net of debt issuance costs.

2 The fair value of SCE's long-term debt is classified as Level 2.

Debt and Credit Agreements

Long-Term Debt

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

(in millions)	SCE
2021	$ 1,029
2022	364
2023	1,035
2024	—
2025	900

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 to be less than or equal to 0.65 to 1. At December 31, 2020, SCE's debt to total capitalization ratio was 0.51 to 1 and was in compliance with all other financial covenants that affect access to capital.

Credit Agreements and Short-Term Debt

The following table summarizes the status of the credit facilities at December 31, 2020:

(in millions, except for rates)

Execution date	Termination date	LIBOR plus (bps)	Use of proceeds	Commitment	Outstanding borrowings	Outstanding letters of credit	Amount available
SCE							
March 2020	March 2021	65	Finance a portion of the AB 1054 Capital Expenditures [1]	$ 800	$ 495	$ —	$ 305
May 2020	May 2021	150	Undercollections related to COVID-19 and general corporate purposes	1,500	—	—	1,500
June 2019	May 2024	108	Support commercial paper borrowings and general corporate purposes [2, 3]	3,000	725	159	2,116
Total SCE:				$ 5,300	$ 1,220	$ 159	$ 3,921

1 SCE and the lenders' have extended the termination date to May 2021. This credit facility may also be extended for two 364-day periods, at the lenders' discretion. The aggregate maximum principal amount may be increased up to $1.1 billion provided that additional lender commitments are obtained.

2 At December 31, 2020 and December 31, 2019, SCE had $725 million and $550 million outstanding commercial paper, net of discount, at a weighted-average interest rate of 0.43% and 2.24%, respectively. As of December 31, 2020, $324 million outstanding commercial paper was classified as long-term debt due to subsequent refinancing. See "Debt Financing Subsequent to December 31, 2020" for more information.

3 The aggregate maximum principal amount under the SCE revolving credit facilities may be increased up to $4.0 billion, provided that additional lender

commitments are obtained.

Term loan and other short-term debt

The following table summarizes the status of SCE's term loan and other short-term debt as of December 31, 2020:

(in millions, except for rates)

Issuance Date	Maturity	LIBOR plus (bps)	Use of Proceeds	Issuance Amount
Term loan				
March 2020	March 2021	60	Fund a portion of the AB 1054 Excluded Capital Expenditures [1]	$ 475
Floating rate first and refunding mortgage bonds				
December 2020	December 2021	27	Partial repayment of AB 1054 credit facility and commercial paper borrowings and for general corporate purposes	900

1 SCE and the lenders' have extended the termination date to May 2021.

Debt Financing Subsequent to December 31, 2020

In January 2021, SCE issued $750 million of 2.95% first and refunding mortgage bonds due in 2051 and $150 million of 2.25% first and refunding mortgage bonds due in 2030. The proceeds were primarily used to repay SCE's commercial paper borrowings and for general corporate purposes.

On April 1, 2021, SCE issued $400 million of Secured Overnight Financing Rate ("SOFR") plus 0.64% first and refunding mortgage bonds due in 2023, $400 million of SOFR plus 0.83% of first and refunding mortgage bonds due in 2024, $350 million of 0.70% first and refunding mortgage bonds due in 2023 and $700 million of 1.10% first and refunding mortgage bonds due in 2024. The proceeds were used to fund the payment of wildfire claims above the amount of expected insurance proceeds, including settlement amounts to be paid under a settlement agreement entered into on January 22, 2021 between SCE and all insurance subrogation plaintiffs in litigation regarding the Woolsey Fire. SCE also intends to use the proceeds to repay commercial paper borrowings that were used to fund the payment of such wildfire claims.

Derivative Instruments

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 PPAs. 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 PPAs 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 and gas contracts contain master netting agreements or similar agreements, which generally allow counterparties subject to the agreement to offset 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 and gas 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 less than $1 million and $1 million as of December 31, 2020 and 2019, respectively, for which SCE has posted no collateral to its counterparties at the respective dates for its derivative liabilities and related outstanding payables for both periods. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2020, SCE would be required to post $3 million of additional collateral, all of which is related to outstanding payables.

Fair Value of Derivative Instruments

SCE presents its derivative assets and liabilities on a net basis on its balance sheets when subject to master netting agreements or similar agreements. Derivative positions are also 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, 2020						
	Derivative Assets			Derivative Liabilities			Net Asset
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 103	$ 23	$ 126	$ 16	$ 6	$ 22	$ 104
Gross amounts offset in the balance sheets	(12)	(6)	(18)	(12)	(6)	(18)	—
Cash collateral posted [1]	—	—	—	(4)	—	(4)	4
Net amounts presented in the balance sheets	$ 91	$ 17	$ 108	$ —	$ —	$ —	$ 108

	December 31, 2019						
	Derivative Assets			Derivative Liabilities			Net Asset
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 94	$ 8	$ 102	$ 14	$ 2	$ 16	$ 86
Gross amounts offset in the balance sheets	(13)	(2)	(15)	(13)	(2)	(15)	—
Cash collateral posted [1]	—	—	—	—	—	—	—
Net amounts presented in the balance sheets	$ 81	$ 6	$ 87	$ 1	$ —	$ 1	$ 86

1 At December 31, 2020, SCE posted $17 million of cash, of which $4 million was offset against derivative liabilities and $13 million was reflected in "Other special funds" (FERC account 128) on the balance sheet. At December 31, 2019, SCE posted $24 million of cash, all of which was not offset against net derivative liabilities and was reflected in "Other special funds" (FERC account 128) on the balance sheet.

Financial 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 purchased 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 reported in cash flows from operating activities in the statements of cash flows.

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

	Years ended December 31,		
(in millions)	2020	2019	2018
Realized gains (losses)	$ 87	$ (7)	$ 26
Unrealized gains (losses)	17	(74)	82

Notional Volumes of Derivative Instruments

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

		Economic Hedges	
	Unit of	December 31,	
Commodity	Measure	2020	2019
Electricity options, swaps and forwards	GWh	1,581	3,155
Natural gas options, swaps and forwards	Bcf	34	43
Congestion revenue rights	GWh	41,151	48,170

Income Taxes

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.

Excess Deferred Taxes

As a result of tax reform and a reduction in the Federal tax rate from 35% to 21% beginning in 2018, all deferred taxes were re-measured at 12/31/2017 to reflect the new tax rate of 21%. The re-measurement of deferred taxes at SCE (i.e. the 14% rate differential from the old rate of 35% to the new rate of 21%) was primarily recorded as an excess deferred tax benefit to regulatory liabilities or an offset to regulatory assets since pre-tax amounts giving rise to the deferred taxes were created through ratemaking activities. FERC accounts 182.3, 190, 282, 283, and 254 were all affected as balances were reclassified from deferred taxes to regulatory liabilities. Since most SCE's deferred taxes arise from property-related differences, SCE estimates that the excess deferred tax benefits will be refunded to customers over approximately 40 or more years.

Both CPUC and FERC have affirmed that excess deferred taxes protected under the normalization rules (as defined by the IRS) are to be returned to ratepayers over the remaining book lives of the assets. SCE has reached settlement agreements with both CPUC and FERC to return unprotected excess deferred taxes (i.e. not subject to the normalization rules) to customers over 3 and 4 years, respectively beginning in 2018.

As of December 31, 2020, $2.3B excess accumulated deferred income tax liabilities (including gross-up) associated with the Tax Cuts and Jobs Act are recorded to either FERC account 182.3 (regulatory asset) or 254 (regulatory liability).

Detail by jurisdiction, protected/unprotected and property/non-property are identified in the table below:

(in millions)	December 31,2019 [1]	ARAM Amortization[2]	December 31,2020
CPUC			
Property			
Protected	$ (1,459)	$ 52	$ (1,407)
Unprotected	(38)	38	-
Cost of Removal	279	-	279
Other		-	-
Rate Base	8	(8)	-
Other Deferred Taxes	-	-	-
CPUC total	$ (1,210)	$ 82	$ (1,128)
FERC			
Property			
Protected	$ (563)	$ 4	$ (559)
Unprotected	(29)	15	(14)
Cost of Removal	56	-	56
Other			
Rate Base	-	-	-
Other Deferred Taxes	-	-	-
FERC Total	$ (536)	$ 19	$ (517)
Total excess deferred taxes	$ (1,746)	$ 101	$ (1,645)
Gross Up on Excess Deferred Taxes			
CPUC	$ (470)	$ 32	$ (438)
FERC	(208)	7	(201)
Total Gross Up	$ (678)	$ 39	$ (639)
Total FERC Account 182.3	$ 884	$ (65)	$ 819
Total FERC Account 254	(3,308)	205	(3,103)
Grand Total	$ (2,424)	$ 140	$ (2,284)

1 The amounts above have been updated to reflect debit and (credit).

2 Excess deferred tax amortization is either recorded to FERC account 410.1 (Debit) or 411.1 (Credit) and the gross up portion is recorded to FERC account 190.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits for continuing and discontinued operations:

	SCE		
(in millions)	2020	2019	2018
Balance at January 1,	$ 282	$ 249	$ 331
Tax positions taken during the current year:			
Increases	56	47	42
Tax positions taken during a prior year:			
Increases	4	6	—
Decreases[1]	(22)	(20)	(121)
Settlements with taxing authorities	—	—	(3)
Balance at December 31,	$ 320	$ 282	$ 249

1 Decrease in 2018 was related to re-measurement as a result of a settlement with the California Franchise Tax Board for tax years 1994 – 2006.

As of December 31, 2020, if recognized, $87 million of the unrecognized tax benefits would impact SCE's effective tax rate.

Tax Disputes

Tax years that remain open for examination by the IRS and the California Franchise Tax Board are 2016 – 2019 and 2013 – 2019, respectively. Tax years 2007 – 2012 are currently subject to a settlement proceeding with the California Franchise Tax Board. SCE does not expect to resolve these tax years within the next 12 months. Any impacts cannot be reasonably estimated until further progress is made.

In the fourth quarter of 2018, SCE recorded the impacts of a settlement reached with the California Franchise Tax Board for tax years 1994 – 2006 that resulted in a $101 million refund of tax and interest. This refund was received in the second quarter of 2019.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to income tax liabilities for continuing and discontinued operations are $23 million and $29 million at December 31, 2020 and 2019, respectively. The net after-tax interest and penalties recognized in income tax expense (benefit) for continuing and discontinued operations are $6 million, $3 million and $(25) million for the years ended December 31, 2020, 2019 and 2018, respectively.

Compensation and Benefit Plans

Employee Savings Plan

The 401(k) defined contribution savings plan is designed to supplement employees' retirement income. The employer contributions were $92 million, $81 million and $74 million for the years ended December 31, 2020, 2019 and 2018, respectively.

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. Employees hired by the Participating Companies on or after December 31, 2017 will no longer be eligible to participate in the Plan. In lieu of that, an additional non-contributory employer contribution will be deposited into the Edison 401(k) Savings Plan. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contributions (all by the employer) SCE are approximately $31 million for the year ending December 31, 2021. Annual contributions made by SCE to most of SCE's pension plans are anticipated to be recovered through CPUC-approved regulatory mechanisms.

The funded position of the 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 the 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 for continuing and discontinued operations is shown below.

	Years ended December 31,	
(in millions)	2020	2019
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,662	$ 3,431
Service cost	117	110
Interest cost	110	138
Actuarial loss	292	199
Benefits paid	(197)	(216)
Projected benefit obligation at end of year	$ 3,984	$ 3,662
Change in plan assets		
Fair value of plan assets at beginning of year	$ 3,541	$ 3,124
Actual return on plan assets	551	576
Employer contributions	45	57
Benefits paid	(197)	(216)
Fair value of plan assets at end of year	3,940	3,541
Funded status at end of year	$ (44)	$ (121)
Amounts recognized in the balance sheets consist of [1]:		
Current liabilities	(2)	(2)
Long-term liabilities	(42)	(119)
	$ (44)	$ (121)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$ —	$ —
Net loss[1]	16	17
	16	17
Amounts recognized as a regulatory asset	12	87
Total not yet recognized as expense	$ 28	$ 104
Accumulated benefit obligation at end of year	$ 3,776	$ 3,529
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	3,984	3,662
Accumulated benefit obligation	3,776	3,529
Fair value of plan assets	3,940	3,541
Weighted average assumptions used to determine obligations at end of year:		
Discount rate	2.38 %	3.11 %
Rate of compensation increase	4.00 %	4.10 %

1 The SCE liability excludes a long-term payable due to Edison International Parent of $139 million and $133 million at December 31, 2020 and 2019, respectively, related to certain SCE postretirement benefit obligations transferred to Edison International Parent. SCE's accumulated other comprehensive loss of $16 million and $17 million at December 31, 2020 and 2019, excludes net losses of $41 million and $37 million related to these benefits, respectively.

The 2020 actuarial losses are primarily related to $305 million in losses from a decrease in the discount rate (from 3.11% as of December 31, 2019 to 2.38% as of December 31, 2020), partially offset by $124 million in gains from other economic assumption changes; the 2019 actuarial losses are primarily related to $373 million in losses from a decrease in the discount rate (from 4.19% as of December 31, 2018 to 3.11% as of December 31, 2019), partially offset by $177 million in gains from other economic assumption changes.

Net periodic pension expense components for continuing operations are:

	Years ended December 31,		
(in millions)	2020	2019	2018
Service cost	$ 119	$ 111	$ 123
Non-service cost			
Interest cost	114	143	128
Expected return on plan assets	(203)	(194)	(214)
Amortization of prior service cost	1	2	3
Amortization of net loss	7	5	6
Regulatory adjustment (deferred)	16	(3)	15
Total non-service benefit	(65)	(47)	(62)
Total expense recognized	$ 54	$ 64	$ 61

Other changes in pension plan assets and benefit obligations recognized in other comprehensive loss for continuing operations:

	Years ended December 31,		
(in millions)	2020	2019	2018
Net loss	$ 9	$ 21	$ 5
Amortization of net loss	(7)	(5)	(6)
Total recognized in other comprehensive loss	2	16	(1)
Total recognized in expense and other comprehensive loss	$ 56	$ 80	$ 60

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.

SCE used the following weighted average assumptions to determine pension expense for continuing operations:

	Years ended December 31,		
	2020	2019	2018
Discount rate	3.11 %	4.19 %	3.46 %
Rate of compensation increase	4.10 %	4.10 %	4.10 %
Expected long-term return on plan assets	6.00 %	6.50 %	6.50 %
Interest crediting rate for cash balance account			
Starting rate	3.61 %	4.46 %	4.36 %
Ultimate rate	5.00 %	5.75 %	5.75 %
Year ultimate rate is reached	2025	2022	2022

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

(in millions)	Years ended December 31,
2021	$ 254
2022	259
2023	262
2024	266
2025	268
2026 – 2030	1,317

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

Employees hired prior to December 31, 2017 who are retiring at or after age 55 with at least 10 years of service may be eligible for postretirement healthcare 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, age, hire date, and retirement date. Employees hired on or after December 31, 2017 are no longer eligible for retiree healthcare benefits. In lieu of those benefits, the Company will provide a health reimbursement account of $200 per month available only after meeting certain age and service year requirements. Under the terms of the Edison International Welfare Benefit Plan ("PBOP Plan"), (which SCE participates in), each participating employer is responsible for the costs and expenses of all PBOP Plan benefits with respect to its employees and former employees that exceed the participants' share of contributions. A participating employer may terminate the PBOP Plan benefits with respect to its employees and former employees, as may SCE (as PBOP Plan sponsor), and, accordingly, the participants' PBOP Plan benefits are not vested benefits.

The expected contributions (substantially all of which are expected to be made by SCE) for PBOP benefits are $9 million for the year ended December 31, 2021. 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 three voluntary employees' beneficiary association trusts ("VEBA Trusts") that can only be used to pay for retiree health care benefits of SCE and its subsidiaries. Once funded into the VEBA Trusts, SCE cannot subsequently 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 Edison International's 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, 2020	2019
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,074	$ 1,977
Service cost	37	30
Interest cost	63	77
Actuarial (gain) loss	(45)	70
Plan participants' contributions	29	29
Benefits paid	(94)	(109)
Benefit obligation at end of year	$ 2,064	$ 2,074
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,464	$ 2,133
Actual return on assets	309	401
Employer contributions	8	10
Plan participants' contributions	29	29
Benefits paid	(93)	(109)
Fair value of plan assets at end of year	2,717	2,464
Funded status at end of year	$ 653	$ 390
Amounts recognized in the balance sheets consist of:		
Long-term assets	$ 663	$ 402
Current liabilities	(10)	(12)
Long-term liabilities	—	—
	$ 653	$ 390
Amounts recognized in accumulated other comprehensive loss consist of:		
Net loss	$ —	$ —
Amounts recognized as a regulatory liability	(671)	(416)
Total not yet recognized as income	$ (671)	$ (416)
Weighted average assumptions used to determine obligations at end of year:		
Discount rate	2.67 %	3.32 %
Assumed health care cost trend rates:		
Rate assumed for following year	6.50 %	6.50 %
Ultimate rate	5.00 %	5.00 %
Year ultimate rate reached	2029	2029

Net periodic PBOP expense components for continuing operations are:

(in millions)	Years ended December 31, 2020	2019	2018
Service cost	$ 37	$ 30	$ 37
Non-service cost			
Interest cost	63	77	80
Expected return on plan assets	(119)	(111)	(122)
Amortization of prior service credit	(1)	(1)	(1)
Amortization of net gain	(29)	(17)	—
Regulatory adjustment	49	29	24
Total non-service benefit	(37)	(23)	(19)
Total expense	$ —	$ 7	$ 18

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. SCE used the following weighted average assumptions to determine PBOP expense for continuing operations:

	Years ended December 31, 2020	2019	2018
Discount rate	3.32 %	4.35 %	3.70 %
Expected long-term return on plan assets	4.90 %	5.30 %	5.30 %
Assumed health care cost trend rates:			
Current year	6.50 %	6.75 %	6.75 %
Ultimate rate	5.00 %	5.00 %	5.00 %
Year ultimate rate reached	2029	2029	2029

The following benefit payments (net of plan participants' contributions) are expected to be paid:

(in millions)	Years ended December 31,
2021	$ 82
2022	84
2023	86
2024	88
2025	90
2026 – 2030	472

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 2020 pension plan assets were 23% for U.S. equities, 17% for non-U.S. equities, 45% for fixed income and 15% for opportunistic and/or alternative investments. Target allocations for 2020 PBOP plan assets (except for Represented VEBA which is 95% for fixed income and 5% for U.S. and non-U.S. equities) are 58% for U.S. and non-U.S. equities, 29% for fixed income and 13% for opportunistic and/or alternative 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 investments are limited partnerships that invest in non-publicly traded entities. Other investments are 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 4% premium above public equity, reflecting a premium for higher volatility and lower liquidity. For fixed income, the risk premium is based on 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. The fair value of the underlying investments in equity mutual funds are based on stock-exchange prices. The fair value of the underlying investments in 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. No investment is classified as Level 3 as of December 31, 2020 and 2019. Common/collective funds and partnerships are measured at fair value using the net asset value per share ("NAV") and have not been classified in the fair value hierarchy. Other investment entities are valued similarly to common/collective funds and are therefore classified as NAV. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable and classified as NAV and are discussed further at the pension plan master trust investments table below.

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 Edison International and SCE that were accounted for at fair value as of December 31, 2020 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	NAV[1]	Total
U.S. government and agency securities[2]	$ 151	$ 1,006	$ —	$ 1,157
Corporate stocks[3]	570	5	—	575
Corporate bonds[4]	—	601	—	601
Common/collective funds[5]	—	—	1,017	1,017
Partnerships/joint ventures[6]	—	—	569	569
Other investment entities[7]	—	—	137	137
Registered investment companies[8]	69	—	23	92
Interest-bearing cash	7	—	—	7
Other	—	39	—	39
Total	$ 797	$ 1,651	$ 1,746	$ 4,194
Receivables and payables, net				(23)
Combined net plan assets available for benefits				4,171
SCE's share of net plan assets				$ 3,940

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2019 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	NAV[1]	Total
U.S. government and agency securities[2]	$ 146	$ 992	$ —	$ 1,138
Corporate stocks[3]	547	7	—	554
Corporate bonds[4]	—	572	—	572
Common/collective funds[5]	—	—	693	693
Partnerships/joint ventures[6]	—	—	471	471
Other investment entities[7]	—	—	130	130
Registered investment companies[8]	133	—	—	133
Interest-bearing cash	7	—	—	7
Other	—	79	—	79
Total	$ 833	$ 1,650	$ 1,294	$ 3,777
Receivables and payables, net				(22)
Combined net plan assets available for benefits				3,755
SCE's share of net plan assets				$ 3,541

1 These investments are measured at fair value using the net asset value per share practical expedient and have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the net plan assets available for benefits.

2 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.

3 Corporate stocks are diversified. Performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (40%) and Morgan Stanley Capital International (MSCI) index (60%), at both December 31, 2020 and 2019.

4 Corporate bonds are diversified. At December 31, 2020 and 2019, respectively, this category includes $54 million and $45 million for collateralized mortgage obligations and other asset backed securities.

5 At December 31, 2020 and 2019, respectively, the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's 500 Index (37% and 35%) and Russell 1000 indexes (13% and 17%). In addition, at December 31, 2020 and 2019, respectively, 40% and 28% of the assets in this category are in index funds which seek to track performance in the MSCI All Country World Index exUS and 8% and 12% of this category are in non-index U.S. equity fund, which is actively managed.

6 At December 31, 2020 and 2019, respectively, 49% and 51% are invested in private equity funds with investment strategies that include branded consumer products and clean technology companies, 23% and 17% are invested in ABS including distressed mortgages and commercial and residential loans, 4% and 8% are invested in a broad range of financial assets in all global markets. 19% are invested in publicly traded fixed income securities for both periods.

7 At both December 31, 2020 and 2019, other investment entities were invested in (1) emerging market equity securities and (2) domestic mortgage backed securities.

8 Level 1 registered investment companies primarily consisted of a global equity mutual fund which seeks to outperform the MSCI World Total Return Index. In addition, investment included fixed income fund used for cash management at December 31, 2020.

At December 31, 2020 and 2019, respectively, approximately 59% and 56% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

Postretirement Benefits Other than Pensions

The following table sets forth the VEBA Trust assets for Edison International and SCE that were accounted for at fair value as of December 31, 2020 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	NAV[1]	Total
U.S. government and agency securities[2]	$ 380	$ 30	$ —	$ 410
Corporate stocks[3]	224	3	—	227
Corporate notes and bonds[4]	—	1,079	—	1,079
Common/collective funds[5]	—	—	693	693
Partnerships[6]	—	—	81	81
Registered investment companies[7]	65	—	—	65
Interest bearing cash	—	26	—	26
Other[8]	—	132	—	132
Total	$ 669	$ 1,270	$ 774	$ 2,713
Receivables and payables, net				4
Combined net plan assets available for benefits				2,717
SCE's share of net plan assets				$ 2,717

The following table sets forth the VEBA Trust assets for Edison International and SCE that were accounted for at fair value as of December 31, 2019 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	NAV[1]	Total
U.S. government and agency securities[2]	$ 386	$ 63	$ —	$ 449
Corporate stocks[3]	242	2	—	244
Corporate notes and bonds[4]	—	885	—	885
Common/collective funds[5]	—	—	652	652
Partnerships[6]	—	—	68	68
Registered investment companies[7]	66	—	—	66
Interest bearing cash	—	17	—	17
Other[8]	2	101	—	103
Total	$ 696	$ 1,068	$ 720	$ 2,484
Receivables and payables, net				(19)
Combined net plan assets available for benefits				2,465
SCE's share of net plan assets				$ 2,464

1 These investments are measured at fair value using the net asset value per share practical expedient and have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the net plan assets available for benefits.

2 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.

3 Corporate stock performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (70% and 68%) and the MSCI All Country World Index (30% and 32%) for 2020 and 2019, respectively.

4 Corporate notes and bonds are diversified and include approximately $170 million and $49 million for commercial collateralized mortgage obligations and other asset backed securities at December 31, 2020 and 2019, respectively.

5 At December 31, 2020 and 2019, respectively, 70% and 74% of the common/collective assets are invested in index funds which seek to track performance in the MSCI All Country World Index Investable Market Index. 22% and 19% are invested in a non-index U.S. equity fund which is actively managed. The remaining assets in this category are primarily invested in emerging market fund.

6 At December 31, 2020 and 2019, respectively, 46% and 55% of the 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. 36% and 28% of the remaining partnerships category are invested in asset backed securities including distressed mortgages, distressed companies and commercial and residential loans and debt and equity of banks. 18% and 15% are invested in a broad range of financial assets in all global markets.

7 At both December 31, 2020 and 2019, registered investment companies were primarily invested in a money market fund and exchange rate trade funds which seek to track performance of MSCI Emerging Market Index, Russell 2000 Index and international small cap equities.

8 Other includes $61 million and $66 million of municipal securities at December 31, 2020 and 2019, respectively.

At December 31, 2020 and 2019, respectively, approximately 66% and 65% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

Stock-Based Compensation

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 approximately 71 million shares. As of December 31, 2020, Edison International had approximately 23 million shares remaining available for new award grants under its stock-based compensation plans.

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

	Years ended December 31,		
(in millions)	2020	2019	2018
Stock-based compensation expense[1]:			
Stock options	$ 7	$ 7	$ 6
Performance shares	2	4	1
Restricted stock units	4	3	4
Other	—	—	—
Total stock-based compensation expense	13	14	11
Income tax benefits related to stock compensation expense	$ 3	$ 6	$ 3

1 Reflected in "Operation and maintenance" on SCE's statements of income.

Stock Options

Under the 2007 Performance Incentive Plan, stock options were granted at exercise prices equal to the closing price at the grant date. Stock options and other awards related to, or with a value derived from, Edison International common stock may be granted 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 in equal annual increments, except for awards granted to retirement-eligible participants, which vest on an accelerated basis.

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,		
	2020	2019	2018
Expected terms (in years)	5.2	5.5	5.7
Risk-free interest rate	0.4% - 0.6%	1.6% - 2.3%	2.6% - 3.0%
Expected dividend yield	4.2% - 5.0%	3.3% - 4.0%	3.6% - 4.3%
Weighted average expected dividend yield	4.7%	3.9%	3.8%
Expected volatility	24.9% - 26.9%	21.7% -24.1%	20.9% - 21.9%
Weighted average volatility	25.0%	21.8%	20.9%

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 corresponds to 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 2020. The volatility period used was 63 months, 66 months and 68 months at December 31, 2020, 2019 and 2018, respectively.

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

		Weighted Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
SCE:				
Outstanding at December 31, 2019	4,934,702	$ 61.01		
Granted	1,053,923	68.27		
Forfeited or expired	(189,691)	65.75		
Exercised[1]	(302,911)	49.49		
Affiliate transfers, net	(5,535)	63.36		
Outstanding at December 31, 2020	5,490,488	62.85	5.86	
Vested and expected to vest at December 31, 2020	5,325,052	62.50	5.98	$ 20
Exercisable at December 31, 2020	3,361,238	$ 60.41	4.56	$ 19

1 SCE recognized tax benefits of $2 million and $2 million, respectively, from stock options exercised in 2020.

At December 31, 2020, total unrecognized compensation cost related to stock options and the weighted average period the cost is expected to be recognized are as follows:

	SCE
Unrecognized compensation cost, net of expected forfeitures (in millions)	$ 9
Weighted average period (in years)	2.3

Supplemental Data on Stock Options

	Years ended December 31,		
(in millions, except per award amounts)	2020	2019	2018
Stock options:			
Weighted average grant date fair value per option granted	$ 8.16	$ 8.83	$ 8.22
Fair value of options vested	2	7	7
Value of options exercised	7	19	7

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2020, 2019 and 2018 and vest at December 31, 2022, 2021 and 2020, respectively. The vesting of the grants is dependent upon market and financial performance 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).

The fair value of market condition performance shares is determined using a *Monte Carlo* simulation valuation model for the total shareholder return. The fair value of financial performance condition performance shares is determined (i) at grant as the target number of shares (which Edison International determined to be the probable outcome) valued at the closing price on the grant date of Edison International common stock and (ii) subsequently using Edison International's earnings per share compared to pre-established targets.

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

	Equity Awards		Liability Awards	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
SCE:				
Nonvested at December 31, 2019	63,172	$ 66.27	58,399	$ 67.34
Granted	64,133	67.15	—	
Forfeited	(6,408)	66.78	(3,409)	
Vested[1]	—	•	(54,578)	
Affiliate transfers, net	(253)	71.27	(412)	
Nonvested at December 31, 2020	120,644	$ 66.70	—	$ —

1 Relates to performance shares that will be paid in 2021 as performance targets were met at December 31, 2020.

Restricted Stock Units

Restricted stock units were awarded to executives in March 2020, 2019 and 2018 and vest and become payable on January 3, 2023, January 3, 2022 and January 4, 2021, 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 restricted stock units is dependent upon continuous service through the end of the vesting period, except for awards granted to retirement-eligible participants, which vest on an accelerated basis.

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

	SCE	
	Restricted Stock Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2019	159,985	$ 66.16
Granted	63,042	68.24
Forfeited	(10,095)	63.93
Vested	(42,549)	79.11
Affiliate transfers, net	(1,963)	68.16
Nonvested at December 31, 2020	168,420	$ 63.78

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

Investments

Nuclear Decommissioning Trusts

Future decommissioning costs related to 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, 2020	Amortized Cost December 31, 2019	Fair Value December 31, 2020	Fair Value December 31, 2019
Stocks	—	N/A	N/A	$ 1,908	$ 1,765
Municipal bonds	2057	1,013	822	1,218	970
U.S. government and agency securities	2067	740	996	864	1,115
Corporate bonds	2070	460	597	550	679
Short-term investments and receivables/payables[1]	One-year	281	32	293	33
Total		$ 2,494	$ 2,447	$ 4,833	$ 4,562

1 Short-term investments include $138 million and $41 million of repurchase agreements payable by financial institutions which earn interest, are fully secured by U.S. Treasury securities and mature by January 4, 2021 and January 2, 2020 as of December 31, 2020 and 2019, 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 $2.1 billion and $1.8 billion at December 31, 2020 and 2019, respectively.

Trust assets are used to pay income taxes. Deferred tax liabilities related to net unrealized gains were $515 million and $449 million at December 31, 2020 and December 31, 2019, respectively. Accordingly, the fair value of trust assets available to pay future decommissioning costs, net of deferred income taxes, totaled $4.3 billion and $4.1 billion at December 31, 2020 and December 31, 2019, respectively.

The following table summarizes the gains and losses for the trust investments:

(in millions)	December 31, 2020	December 31, 2019	December 31, 2018
Gross realized gains	$ 255	$ 87	$ 134
Gross realized losses	(6)	(2)	(27)
Net unrealized gains (losses) for equity securities	176	343	(233)

Due to regulatory mechanisms, changes in assets of the trusts from income or loss items have no impact on operating revenue or earnings.

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 7.68% and 7.61% in 2020 and 2019, respectively. The CPUC 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.

In accordance with the accounting standards applicable to rate-regulated enterprises, SCE defers costs as regulatory assets that are probable of future recovery from customers and has recorded regulatory assets for these incremental costs at December 31, 2020. While SCE believes such costs are probable of future recovery, there is no assurance that SCE will collect all amounts currently deferred as regulatory assets. SCE's regulatory assets related to power contracts primarily represent derivative contracts that were designated as normal purchases and normal sales contracts. The liabilities for these power contracts are amortized over the remaining contract terms, approximately 2 to 3 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 has long-term unamortized investments which include nuclear assets related to Palo Verde and the beyond the meter program. Nuclear assets related to Palo Verde and the beyond the meter program are expected to be recovered by 2044 and 2027, respectively, and earned returns of 7.68% and 7.61% in 2020 and 2019, respectively.

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 10 to 40 years or the life of the new issuance if the debt is refunded or refinanced. SCE's regulatory assets related to environmental remediation represent 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 energy derivatives are primarily an offset to unrealized gains on derivatives.

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

As a result of Tax Reform, SCE's deferred tax assets and liabilities were re-measured at December 31, 2017, resulting in the initial recording of regulatory liabilities. The amount was further adjusted for CPUC's final resolution in February 2019, which stated that customers are only entitled to re-measurement of deferred taxes that were included when setting rates (i.e. included in rate base), and that all other deferred tax re-measurements belong to shareholders. The regulatory liabilities are generally expected to be refunded to customers over the lives of the assets and liabilities that gave rise to the deferred taxes.

SCE's regulatory liabilities related to recoveries in excess of ARO liabilities represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the SCE's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments.

SCE's regulatory liabilities related to other postretirement benefits represent the overfunded net actuarial gain. This amount will be refunded through rates charged to customers.

Net Regulatory Balancing and Memorandum Accounts

Balancing accounts track amounts that the CPUC or FERC have authorized for recovery. 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. Memorandum accounts are authorized to track costs for potential future recovery. Under and over collections in balancing accounts and amounts recorded in memorandum accounts typically accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

Commitments and Contingencies

Power Purchase Agreements

SCE entered into various agreements to purchase power, electric capacity and other energy products. At December 31, 2020, the undiscounted future expected minimum payments for the SCE PPAs (primarily related to renewable energy contracts), which were approved by the CPUC and met other critical contract provisions (including completion of major milestones for construction), were as follows:

(in millions)	Total
2021	$ 3,144
2022	3,066
2023	2,937
2024	2,349
2025	2,236
Thereafter	21,756
Total future commitments[1]	$ 35,488

1 Certain power purchase agreements are treated as operating or finance leases. Includes lease contracts commencing in 2021, 2022 and 2023 with future short-term lease expense of $242 million in 2021 and long-term minimum lease payments of $866 million.

Additionally, as of December 31, 2020, SCE has executed contracts (including capacity reduction contracts) that have not met the critical contract provisions that would increase contractual obligations by $29 million in 2021, $72 million in 2022, $93 million in 2023, $111 million in 2024, $111 million in 2025 and $1.2 billion thereafter, if all critical contract provisions are completed.

Costs incurred for PPAs were $3.8 billion in 2020, $3.7 billion in 2019 and $3.8 billion in 2018, which include costs associated with contracts with terms of less than one year.

Other Commitments

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

(in millions)	2021	2022	2023	2024	2025	Thereafter	Total
Other contractual obligations	$ 46	$ 43	$ 43	$ 45	$ 37	$ 154	$ 368

Costs incurred for other commitments were $80 million in 2020, $110 million in 2019 and $124 million in 2018. Other commitments include fuel supply contracts for Palo Verde which require payment only if the fuel is made available for purchase. Also included are commitments related to maintaining reliability and expanding SCE's transmission and distribution system.

The table above does not include asset retirement obligations.

Indemnities

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

SCE have agreed to provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, indemnities for specified environmental liabilities and income taxes with respect to assets sold or other contractual arrangements. 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 have not recorded a liability related to these indemnities. The overall maximum amount of the obligations under these indemnifications cannot be reasonably estimated.

Leases

Leases as Lessee

SCE enters into various agreements to purchase power, electric capacity and other energy products that may be accounted for as leases when SCE has dispatch rights that determine when and how a plant runs. SCE also leases property and equipment primarily related to vehicles, office space and other equipment. The terms of the contracts included in the table below are primarily 3 to 20 years for PPA leases, 5 to 72 years for office leases, and 5 to 13 years for the remaining other operating leases.

The following table summarizes SCE's lease payments for operating and finance leases as of December 31, 2020:

(in millions)	PPA Operating Leases[1]	Other Operating Leases[2]	PPA Finance Leases[1]
2021	$ 204	$ 39	$ 1
2022	208	32	1
2023	159	26	1
2024	47	21	—
2025	47	18	—
Thereafter	443	104	5
Total lease payments	1,108	240	8
Amount representing interest[3]	203	60	4
Lease liabilities	$ 905	$ 180	$ 4

1 Excludes expected purchases from most renewable energy contracts, which do not meet the definition of a lease payment since renewable power generation is contingent on external factors.

2 Excludes escalation clauses based on consumer price or other indices and residual value guarantees that are not considered probable at the commencement date of the lease.

3 Lease payments are discounted to their present value using SCE's incremental borrowing rates.

Supplemental balance sheet information related to SCE's leases was as follows:

(in millions)	December 31, 2020		December 31, 2019	
Operating leases:				
Utility Plant[1]	$	1,085	$	689
Obligation under capital leases-current		214		79
Obligation under capital leases-noncurrent		871		610
Total operating lease liabilities[1]	$	1,085	$	689
Finance leases included in:				
Utility plant	$	4	$	14
Accumulated depreciation		—		(5)
Utility plant, net		4		9
Obligation under capital leases-current		—		1
Obligation under capital leases-noncurrent		4		8
Total finance lease liabilities	$	4	$	9

1 During the year ended 2020, a PPA operating lease commenced and one PPA was amended resulting in a total of $463 million additions in Utility plant and Obligation under capital lease.

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 for operating leases and interest and amortization expense for finance leases. The following table summarizes the components of SCE's lease expense:

(in millions)	Year ended December 31, 2020		Year ended December 31, 2019	
PPA leases:				
Operating lease cost	$	111	$	118
Finance lease cost		1		1
Variable lease cost[1]		1,917		2,087
Total PPA lease cost		2,029		2,206
Other operating leases cost		47		46
Total lease cost	$	2,076	$	2,252

1 Includes lease costs from renewable energy contracts where payments are based on contingent external factors such as wind, hydro and solar power generation.

Other information related to leases was as follows:

(in millions, except lease term and discount rate)	Year ended December 31, 2020	Year ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases		
PPA leases	$ 111	$ 118
Other leases	44	44
Financing cash flows from PPA finance leases	1	1
Operating lease assets obtained in exchange for lease obligations:		
PPA operating leases	$ 463	—
Other operating leases	58	34
Weighted average remaining lease term (in years):		
Operating leases		
PPA leases	9.75	16.05
Other leases	12.13	12.73
PPA Finance leases	16.67	11.51
Weighted average discount rate:		
Operating leases		
PPA leases	3.12 %	4.46 %
Other leases	3.63 %	3.88 %
PPA Finance leases	11.29 %	8.76 %

Leases as Lessor

SCE also enters into operating leases to rent certain land and facilities as a lessor. These leases primarily have terms that range from 15 to 65 years. During the twelve months ended December 31, 2020 and December 31, 2019, SCE recognized $17 million and $18 million, respectively, in lease income, which is included in operating revenue on the statements of income. At December 31, 2020, the undiscounted cash flow expected to be received from lease payments for the remaining years is as follows:

(in millions)		
2021	$	11
2022		10
2023		8
2024		7
2025		6
Thereafter		128
Total	$	170

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. There are no dividends in arrears for the preferred or preference shares.

During the third quarter of 2020, SCE redeemed $120 million of cumulative preferred stock consisting of all of the outstanding shares of the 4.32% Series, 4.08% Series, 4.24% Series and the 4.78% Series at a price of $28.75, $25.50, $25.80 and $25.80, respectively. SCE recorded a $9 million loss on the redemption of the preferred stock as an adjustment to net income available to common stockholders. No preferred shares were issued or redeemed in the years ended December 31, 2019 and 2018. There is no sinking fund requirement for redemptions or repurchases of preferred shares.

Shares of SCE's preference stock rank 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. SCE's outstanding preference shares are not subject to mandatory redemption and there is no sinking fund requirement for redemptions or repurchases of preference shares. Shares of Series E preference stock issued in 2012 may be redeemed at par, in whole or in part, on or after February 1, 2022. Shares of Series G, H, J, K and L preference stock, issued in 2013, 2014, 2015, 2016 and 2017, respectively, may be redeemed at par, in whole, but not in part, at any time prior to March 15, 2018, March 15, 2024, September 15, 2025, March 15, 2026 and June 26, 2022, respectively, if certain changes in tax or investment company law or interpretation (or applicable rating agency equity credit criteria for Series L only) occur and certain other conditions are satisfied. On or after March 15, 2018, March 15, 2024, September 15, 2025, March 15, 2026 and June 26, 2022, SCE may redeem the Series G, H, J, K and L shares, respectively, at par, in whole or in part. For shares of Series H, J and K preference stock, distributions will accrue and be payable at a floating rate from and including March 15, 2024, September 15, 2025 and March 15, 2026, respectively. Shares of Series G, H, J, K and L preference stock were issued to SCE Trust II, SCE Trust III, SCE Trust IV, SCE Trust V and SCE Trust VI, respectively, special purpose entities formed to issue trust securities. During the third quarter of 2020, SCE redeemed $180 million of the outstanding shares of the Series G preference stock. SCE recorded a $6 million loss on the redemption of the preference stock as an adjustment to net income available to common stockholders. No preference shares were issued or redeemed in the years ended December 31, 2019 and 2018.

Supplemental Cash Flows Information

Supplemental cash flows information is:

	Years ended December 31,		
(in millions)	2020	2019	2018
Cash payments (receipts):			
Interest, net of amounts capitalized	$ 713	$ 615	$ 552
Income taxes, net	(50)	(164)	(57)
Non-cash financing and investing activities:			
Dividends declared but not paid:			
Common stock	—	200	—
Preferred and preference stock	11	12	12

SCE's accrued capital expenditures at December 31, 2020, 2019 and 2018 were $730 million, $643 million and $594 million, respectively. Accrued capital expenditures will be included as an investing activity in the statements of cash flow in the period paid.

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 performed by Edison International or SCE employees, such as payroll and employee benefit programs, 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 revenue, 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.

For the years ended December 31, 2020, 2019 and 2018, SCE purchased wildfire liability insurance for premiums of $176 million, $260 million and $22 million respectively, from Edison Insurance Services, Inc. ("EIS"), a wholly-owned subsidiary of Edison International. EIS fully reinsured the exposure for these policies through the commercial reinsurance market, with reinsurance limits and premiums equal to those of the insurance purchased by SCE. The related-party transactions included in SCE's balance sheets for wildfire-related insurance purchased from EIS and related expected insurance recoveries were as follows:

	December 31,	
(in millions)	2020	2019
Current insurance receivable due from affiliate	$ 268	$ —
Long-term insurance receivables due from affiliate	—	803
Prepaid insurance	56	10

The expense for wildfire-related insurance premiums paid to EIS were $189 million, $173 million and $140 million for the years ended December 31, 2020, 2019 and 2018 respectively.

ITEM 2. SIGNIFICANT CONTINGENCIES

Contingencies

In addition to the matters disclosed in these Notes, Edison International and SCE are involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International and SCE believe the outcome of each of these other proceedings will not materially affect its financial position, results of operations and cash flows.

Southern California Wildfires and Mudslides

Wildfires in SCE's territory, including those where SCE's equipment may be alleged to be associated with the fire's ignition, have caused loss of life and substantial damage in recent years. Multiple factors have contributed to increased wildfire activity and faster progression of wildfires across SCE's service territory and in other areas of California. These include the buildup of dry vegetation in areas severely impacted by years of historic drought, lack of adequate clearing of hazardous fuels by responsible parties, higher temperatures, lower humidity, increased incidence of dry lightning, and strong Santa Ana winds. At the same time that wildfire risk has been increasing in Southern California, residential and commercial development has occurred and is occurring in some of the highest-risk areas. Such factors can increase the likelihood and extent of wildfires. SCE has determined that approximately 27% of its service territory is in areas identified as high fire risk.

California has experienced unprecedented weather conditions in recent years and SCE's service territory remains susceptible to additional wildfire activity in 2021 and beyond. The worsening conditions across California increase the likelihood of wildfires, including those where SCE's equipment may be alleged to be associated with the fire's ignition. In response to worsening weather and fuel conditions and increased wildfire activity over the past several years, SCE has developed and is implementing its 2020 – 2022 Wildfire Mitigation Plan ("WMP") to reduce the risk of SCE equipment contributing to the ignition of wildfires. In addition, California has increased its investment in wildfire suppression capabilities.

In addition to the investments SCE is making through its WMP, SCE also uses its Public Safety Power Shutoffs ("PSPS") program to proactively de-energize power lines to mitigate the risk of catastrophic wildfires during extreme weather events. SCE initiated PSPS 12 times in 2020 as part of its wildfire mitigation efforts, impacting an aggregate of approximately 140,000 unique customers. In January 2021, the President of the CPUC sent SCE a letter expressing her concern regarding SCE's execution of PSPS in 2020 and notifying SCE that it must implement a PSPS action plan to reduce the impacts of PSPS on the customers and communities it serves. On a risk-informed basis, SCE is making efforts to reduce the frequency and impacts of PSPS in 2021 as compared to 2020, assuming that weather patterns in 2021 are similar to those experienced in 2020. SCE may be subject to mandated changes to, or restrictions on, its operational PSPS practices, regulatory fines and penalties, claims for damages and reputational harm if SCE does not execute PSPS in compliance with applicable rules and regulations or if it is determined that SCE has placed excessive reliance on PSPS.

Edison International and SCE accrued estimated losses of $1,328 million in 2020 for wildfire-related claims, net of expected insurance recoveries. The 2020 charge includes an increase in estimated losses for claims related to the 2017/2018 Wildfire/Mudslide Events (defined below) of $1,297 million, against which SCE has recorded expected recoveries through FERC electric rates of $84 million. The resulting charge was $1,213 million ($874 million after-tax). The 2020 charge also includes $31 million ($21 million after FERC recovery and after-tax) of expenses primarily associated with self-insured retention related to the 2019/2020 Wildfires (defined below).

Edison International and SCE have incurred material losses in connection with the 2017/2018 Wildfire/Mudslide Events, which are described below. Several wildfires have originated in Southern California subsequent to 2018, however, Edison International and SCE expect that any losses incurred in connection with these fires will be covered by insurance, subject to self-insured retentions and co-insurance, and expect that any such losses after insurance recoveries will not be material.

Liability Overview

The extent of liability for wildfire-related damages in actions against utilities depends on a number of factors, including whether the utility substantially caused or contributed to the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation. California courts have previously found utilities to be strictly liable for property damage along with associated interest and attorneys' fees, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. If inverse condemnation is held to be inapplicable to SCE in connection with a wildfire, SCE still could be held liable for property damages and associated interest if the property damages were found to have been proximately caused by SCE's negligence. If SCE were to be found negligent, SCE could also be held liable for, among other things, fire suppression costs, business interruption losses, evacuation costs, clean-up costs, medical expenses, and personal injury/wrongful death claims. Additionally, SCE could potentially be subject to fines for alleged violations of CPUC rules and state laws in connection with the ignition of a wildfire.

Final determinations of liability for wildfire events, including determinations of whether SCE was negligent, would only be made during lengthy and complex litigation processes. Even when investigations are still pending or liability is disputed, an assessment of likely outcomes, including through future settlement of disputed claims, may require estimated losses to be accrued under accounting standards. Each reporting period, management reviews its loss estimates for remaining alleged and potential claims related to wildfire events. The process for estimating losses associated with alleged and potential wildfire-related claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including, but not limited to: estimates of known and expected claims by third parties based on currently available information, opinions of counsel regarding litigation risk, the status of and developments in the course of litigation, and prior experience litigating and settling wildfire litigation claims. As additional information becomes available, management's estimates and assumptions regarding the causes and financial impact of wildfire events may change.

2019/2020 Wildfires

Several wildfires significantly impacted portions of SCE's service territory in 2019 and 2020 (the wildfires that originated in Southern California in 2019 and 2020 where SCE's equipment may be alleged to be associated with the fire's ignition are referred to collectively as the "2019/2020 Wildfires"). Edison International and SCE expect that any losses incurred in connection with the 2019/2020 Wildfires will be covered by insurance, subject to self-insured retentions and co-insurance, and expect that any such losses after insurance recoveries will not be material. As of December 31, 2020, Edison International and SCE had estimated losses (established at the lower end of the reasonably estimated range of expected losses) of $117 million reflected on their balance sheets related to the 2019/2020 Wildfires. As of the same date, Edison International and SCE also had assets for expected recoveries from insurance of $75 million and expected recoveries from FERC of $3 million on their balance sheets related to the 2019/2020 Wildfires.

One of the 2019/2020 Wildfires, the "Saddle Ridge" Fire, originated in Los Angeles county in October 2019 and burned approximately 9,000 acres, destroyed an estimated 19 structures, damaged an estimated 88 structures, and resulted in injuries to 8 individuals and one fatality. An investigation into the cause of the Saddle Ridge Fire is being led by the Los Angeles Fire Department. Based on pending litigation and without considering insurance recoveries, it is reasonably possible that SCE will incur a material loss in connection with the Saddle Ridge Fire, but the range of possible losses that could be incurred cannot be estimated at this time. SCE has not accrued a charge for potential losses relating to the Saddle Ridge Fire.

Another of the 2019/2020 Wildfires, the "Bobcat Fire" was reported in the vicinity of Cogswell Dam in Los Angeles County, California in September 2020. The United States Forest Service ("USFS") has reported that the Bobcat Fire burned approximately 116,000 acres in Los Angeles County, destroyed an estimated 87 homes, 1 commercial property and 83 minor structures, damaged an estimated 28 homes and 19 minor structures, and resulted in injuries to 6 firefighters. In addition, the USFS has estimated suppression costs at $80 million. A camera in the vicinity of Cogswell Dam captured the initial stages of a fire with the first observed smoke approximately six minutes before an SCE circuit in the area experienced an anomaly (a relay). An investigation into the cause of the Bobcat Fire is being led by the USFS, and the USFS has taken a specific section of an SCE overhead conductor in the vicinity of Cogswell Dam into possession as part of its investigation. SCE understands that the USFS has also taken three tree branches in the area into possession. The SED is also conducting an investigation of the Bobcat Fire. SCE has accrued a charge for potential losses relating to the Bobcat Fire. The accrued charge corresponds to the lower end of the reasonably estimated range of expected losses that may be incurred in connection with the Bobcat Fire and is subject to change as additional information becomes available.

2017/2018 Wildfire/Mudslide Events

Wildfires in SCE's territory in December 2017 and November 2018 caused loss of life, substantial damage to both residential and business properties, and service outages for SCE customers. The investigating government agencies, the Ventura County Fire Department ("VCFD") and California Department of Forestry and Fire Protection ("CAL FIRE"), have determined that the largest of the 2017 fires in SCE's territory originated on December 4, 2017, in the Anlauf Canyon area of Ventura County (the investigating agencies refer to this fire as the "Thomas Fire"), followed shortly thereafter by a second fire that originated near Koenigstein Road in the City of Santa Paula (the "Koenigstein Fire"). The December 4, 2017 fires eventually burned substantial acreage in both Ventura and Santa Barbara Counties. According to CAL FIRE, the Thomas and Koenigstein Fires, collectively, burned over 280,000 acres, destroyed or damaged an estimated 1,343 structures and resulted in two confirmed fatalities. The largest of the November 2018 fires in SCE's territory, known as the "Woolsey Fire," originated in Ventura County and burned acreage in both Ventura and Los Angeles Counties. According to CAL FIRE, the Woolsey Fire burned almost 100,000 acres, destroyed an estimated 1,643 structures, damaged an estimated 364 structures and resulted in three confirmed fatalities. Two additional fatalities have been associated with the Woolsey Fire. The Thomas Fire, the Koenigstein Fire, the Montecito Mudslides (defined below) and the Woolsey Fire are each referred to as a "2017/2018 Wildfire/Mudslide Event," and, collectively, referred to as the "2017/2018 Wildfire/Mudslide Events."

As described below, multiple lawsuits related to the Thomas and Koenigstein Fires and the Woolsey Fire have been initiated against SCE and Edison International. Some of the Thomas and Koenigstein Fires lawsuits claim that SCE and Edison International have responsibility for the damages caused by debris flows and flooding in Montecito and surrounding areas in January 2018 (the "Montecito Mudslides") based on a theory alleging that SCE has responsibility for the Thomas and/or Koenigstein Fires and further alleging that the Thomas and/or Koenigstein Fires proximately caused the Montecito Mudslides. According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures, and resulted in 21 confirmed fatalities, with two additional fatalities presumed. Based on information available to SCE and consideration of the risks associated with litigation, Edison International and SCE expect to incur a material loss in connection with the remaining alleged and potential claims related to the 2017/2018 Wildfire/Mudslide Events. The 2017/2018 Wildfire/Mudslide Events are discussed further below.

As of December 31, 2020, Edison International and SCE had paid $1.8 billion in settlements and had estimated losses of $4.4 billion reflected on their balance sheets related to the 2017/2018 Wildfire/Mudslide Events, consisting of $2.2 billion subject to settlements executed after December 31, 2020 and $2.2 billion for remaining alleged and potential claims. As of the same date, Edison International and SCE also had assets for remaining expected recoveries from insurance of $708 million, reflected as a short-term asset, and through FERC electric rates of $89 million on their balance sheets related to the 2017/2018 Wildfire/Mudslide Events. The estimated losses for the 2017/2018 Wildfire/Mudslide Events do not include an estimate of any potential fines or penalties that could be levied against SCE in connection with the 2017/2018 Wildfire/Mudslide Events. Edison International and SCE are currently unable to reasonably estimate the magnitude of any such fines or penalties, or the associated timing if they were to be imposed. Estimated losses for the 2017/2018 Wildfire/Mudslide Events litigation are based on a number of assumptions and are subject to change as additional information becomes available. Actual losses incurred may be higher or lower than estimated based on several factors, including: the uncertainty as to the legal and factual determinations to be made during litigation, including uncertainty as to the contributing causes of the 2017/2018 Wildfire/Mudslide Events, the complexities associated with fires that merge, whether inverse condemnation will be held applicable to SCE with respect to damages caused by the Montecito Mudslides, the preliminary nature of the litigation processes, the uncertainty in estimating damages that may be alleged, and the uncertainty as to how these factors impact future settlements.

The CPUC and FERC may not allow SCE to recover uninsured losses through electric rates if it is determined that such losses were not reasonably or prudently incurred. See "Loss Estimates for Third Party Claims and Potential Recoveries from Insurance and through Electric Rates" below for additional information.

External Investigations and Internal Review

The VCFD and CAL FIRE have jointly issued reports concerning their findings regarding the causes of the Thomas Fire and the Koenigstein Fire. The reports did not address the causes of the Montecito Mudslides. SCE has also received a non-final redacted draft of a report from the VCFD regarding Woolsey Fire (the "Redacted Woolsey Report"). SCE anticipates that the VCFD will release its final report regarding the Woolsey Fire in 2021. The VCFD and CAL FIRE findings do not determine legal causation of or assign legal liability for the Thomas, Koenigstein or Woolsey Fires; final determinations of legal causation and liability would only be made during lengthy and complex litigation.

The CPUC's Safety and Enforcement Division ("SED") is also conducting investigations to assess SCE's compliance with applicable rules and regulations in areas impacted by the Thomas, Koenigstein and Woolsey Fires and the CPUC may initiate proceedings to investigate these matters after the SED's investigations are completed.

Edison International and SCE understand that the California Attorney General's Office has completed its investigation of the Thomas Fire without pursuing criminal charges. Edison International and SCE are aware of an ongoing investigation by the California Attorney General's Office of the Woolsey Fire for the purpose of determining whether any criminal violations have occurred. SCE could be subject to material fines, penalties, or restitution if it is determined that it failed to comply with applicable laws and regulations. SCE is not aware of any basis for felony liability with regards to the Thomas Fire, the Koenigstein Fire or the Woolsey Fire.

SCE's internal review into the facts and circumstances of each of the 2017/2018 Wildfire/Mudslide Events is complex and time consuming. SCE expects to obtain and review additional information and materials in the possession of third parties during the course of its internal reviews and the litigation processes.

Thomas Fire

On March 13, 2019, the VCFD and CAL FIRE jointly issued a report concluding, after ruling out other possible causes, that the Thomas Fire was started by SCE power lines coming into contact during high winds, resulting in molten metal falling to the ground. However, the report does not state that their investigation found molten metal on the ground. At this time, based on available information, SCE has not determined whether its equipment caused the Thomas Fire. Based on publicly available radar data showing a smoke plume in the Anlauf Canyon area emerging in advance of the report's indicated start time, SCE believes that the Thomas Fire started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated in the report. SCE is continuing to assess the extent of damages that may be attributable to the Thomas Fire.

Koenigstein Fire

On March 20, 2019, the VCFD and CAL FIRE jointly issued a report finding that the Koenigstein Fire was caused when an energized SCE electrical wire separated and fell to the ground along with molten metal particles and ignited the dry vegetation below. As previously disclosed, SCE believes that its equipment was associated with the ignition of the Koenigstein Fire. SCE is continuing to assess the extent of damages that may be attributable to the Koenigstein Fire.

Montecito Mudslides

SCE's internal review includes inquiry into whether the Thomas and/or Koenigstein Fires proximately caused or contributed to the Montecito Mudslides, whether, and to what extent, the Thomas and/or Koenigstein Fires were responsible for the damages in the Montecito area and other factors that potentially contributed to the losses that resulted from the Montecito Mudslides. Many other factors, including, but not limited to, weather conditions and insufficiently or improperly designed and maintained debris basins, roads, bridges and other channel crossings, could have proximately caused, contributed to or exacerbated the losses that resulted from the Montecito Mudslides.

At this time, based on available information, SCE has not been able to determine whether the Thomas Fire or the Koenigstein Fire, or both, were responsible for the damages in the Montecito area. In the event that SCE is determined to have caused the fire that spread to the Montecito area, SCE cannot predict whether, if fully litigated, the courts would conclude that the Montecito Mudslides were caused or contributed to by the Thomas and/or Koenigstein Fires or that SCE would be liable for some or all of the damages caused by the Montecito Mudslides.

Woolsey Fire

SCE's internal review into the facts and circumstances of the Woolsey Fire is ongoing. SCE has reported to the CPUC that there was an outage on SCE's electric system in the vicinity of where the Woolsey Fire reportedly began on November 8, 2018. SCE is aware of witnesses who saw fire in the vicinity of SCE's equipment at the time the fire was first reported. While SCE did not find evidence of downed electrical wires on the ground in the suspected area of origin, it observed a pole support wire in proximity to an electrical wire that was energized prior to the outage.

The Redacted Woolsey Report states that the VCFD investigation team determined that electrical equipment owned and operated by SCE was the cause of the Woolsey Fire. Absent additional evidence, SCE believes that it is likely that its equipment was associated with the ignition of the Woolsey Fire. SCE expects to obtain and review additional information and materials in the possession of CAL FIRE and others during the course of its internal review and the Woolsey Fire litigation process, including SCE equipment that has been retained by CAL FIRE.

Litigation

Multiple lawsuits related to the 2017/2018 Wildfire/Mudslide Events naming SCE as a defendant have been filed by three categories of plaintiffs: individual plaintiffs, subrogation plaintiffs and public entity plaintiffs. A number of the lawsuits also name Edison International as a defendant and some of the lawsuits were filed as purported class actions. Because potential plaintiffs can still timely file claims related to the 2017/2018 Wildfire/Mudslide Events, SCE expects to be the subject of additional lawsuits related to the events. The litigation could take a number of years to be resolved because of the complexity of the matters and number of plaintiffs.

As of February 18, 2021, SCE was aware of at least 295 lawsuits, representing approximately 4,000 plaintiffs, related to the Thomas and Koenigstein Fires naming SCE as a defendant. One hundred fifty of the 295 lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. At least four of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura, Santa Barbara and Los Angeles Counties allege, among other things, negligence, inverse condemnation, trespass, private nuisance, and violations of the public utilities and health and safety codes. An initial trial for a limited number of plaintiffs, sometimes referred to as a bellwether trial, on certain fire only matters is currently scheduled for July 19, 2021. The bellwether trial date may be further delayed to provide SCE and certain of the individual plaintiffs in the Thomas and Koenigstein Fire litigation the opportunity to pursue settlements of claims under a program adopted to promote an efficient and orderly settlement process.

Seventy-two of the 295 lawsuits mentioned in the paragraph above allege that SCE has responsibility for the Thomas and/or Koenigstein Fires and that the Thomas and/or Koenigstein Fires proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. Forty of the 72 Montecito Mudslides lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. In addition to other causes of action, some of the Montecito Mudslides lawsuits also allege personal injury and wrongful death. A bellwether jury trial previously scheduled for October 12, 2020 was vacated due to the wide-spread disruption being caused by the COVID-19 pandemic.

As of February 18, 2021, SCE was aware of at least 301 lawsuits, representing approximately 6,000 plaintiffs, related to the Woolsey Fire naming SCE as a defendant. Two hundred forty-three of the 301 lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. At least two of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura and Los Angeles Counties allege, among other things, negligence, inverse condemnation, personal injury, wrongful death, trespass, private nuisance, and violations of the public utilities and health and safety codes. A bellwether jury trial is currently scheduled for June 1, 2021.

The Thomas and Koenigstein Fires and Montecito Mudslides lawsuits are being coordinated in the Los Angeles Superior Court. The Woolsey Fire lawsuits have also been coordinated in the Los Angeles Superior Court. On October 4, 2018, the Superior Court denied Edison International's and SCE's challenge to the application of inverse condemnation to SCE with respect to the Thomas and Koenigstein Fires and, on February 26, 2019, the California Supreme Court denied SCE's petition to review the Superior Court's decision. In January 2019, SCE filed a cross-complaint against certain local public entities alleging that failures by these entities, such as failure to adequately plan for flood hazards and build and maintain adequate debris basins, roads, bridges and other channel crossings, among other things, caused, contributed to or exacerbated the losses that resulted from the Montecito Mudslides. These cross-claims in the Montecito Mudslides litigation were not released as part of the Local Public Entity Settlements (as defined below).

Additionally, in September 2018, a derivative lawsuit for breach of fiduciary duties and unjust enrichment was filed in the Los Angeles Superior Court against certain current and former members of the Boards of Directors of Edison International and SCE. Edison International and SCE are identified as nominal defendants in the action. The derivative lawsuit generally alleges that the individual defendants violated their fiduciary duties by causing or allowing SCE to operate in an unsafe manner in violation of relevant regulations, resulting in substantial liability and damage from the Thomas and Koenigstein Fires and the Montecito Mudslides. The lawsuit is currently stayed.

In November 2018, a purported class action lawsuit alleging securities fraud and related claims was filed in federal court against Edison International, SCE and certain current and former officers of Edison International and SCE. The plaintiff alleges that Edison International and SCE made false and/or misleading statements in filings with the Securities and Exchange Commission by failing to disclose that SCE had allegedly failed to maintain its electric transmission and distribution networks in compliance with safety regulations, and that those alleged safety violations led to fires that occurred in 2017 and 2018, including the Thomas Fire and the Woolsey Fire.

In January 2019, two separate derivative lawsuits alleging breach of fiduciary duties, securities fraud, misleading proxy statements, unjust enrichment, and related claims were filed in federal court against certain current and former members of the Boards of Directors and certain current and former officers of Edison International and SCE. Edison International and SCE are named as nominal defendants in those actions. The derivative lawsuits generally allege that the individual defendants breached their fiduciary duties and made misleading statements or allowed misleading statements to be made (i) between March 21, 2014 and August 10, 2015, with respect to certain *ex parte* communications between SCE and CPUC decision-makers concerning the settlement of the San Onofre Order Instituting Investigation proceeding (the "San Onofre OII") and (ii) from February 23, 2016 to the present, concerning compliance with applicable laws and regulations concerning electric system maintenance and operations related to wildfire risks. The lawsuits generally allege that these breaches of duty and misstatements led to substantial liability and damage resulting from the disclosure of SCE's *ex parte* communications in connection with the San Onofre OII settlement, and from the 2017/2018 Wildfire/Mudslide Events. The lawsuits are currently stayed.

Settlements

In the fourth quarter of 2019, SCE paid $360 million to a number of local public entities to resolve those parties' collective claims arising from the 2017/2018 Wildfire/Mudslide Events (the "Local Public Entity Settlements").

In the third quarter of 2020, Edison International and SCE entered into an agreement (the "TKM Subrogation Settlement") under which all of the insurance subrogation plaintiffs' in the Thomas Fire, Koenigstein Fire and Montecito Mudslides litigation (the "TKM Subrogation Plaintiffs") collective claims arising from the Thomas Fire, Koenigstein Fire or Montecito Mudslides have been resolved. Under the TKM Subrogation Settlement, SCE paid the TKM Subrogation Plaintiffs an aggregate of $1.2 billion in October 2020 and also agreed to pay $0.555 for each dollar in claims to be paid by the TKM Subrogation Plaintiffs to their policy holders on or before July 15, 2023, up to an agreed upon cap.

In January 2021, Edison International and SCE entered into an agreement (the "Woolsey Subrogation Settlement") under which all of the insurance subrogation plaintiffs' in the Woolsey Fire litigation (the "Woolsey Subrogation Plaintiffs") collective claims arising from the Woolsey Fire have been resolved. Under the Woolsey Subrogation Settlement, SCE agreed to pay the Woolsey Subrogation Plaintiffs an aggregate of $2.2 billion by April 22, 2021. SCE has also agreed to pay $0.67 for each dollar in claims to be paid by the

Woolsey Subrogation Plaintiffs to their policy holders on or before July 15, 2023, up to an agreed upon cap.

As of February 18, 2021, SCE has also entered into settlements with approximately one thousand individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation. In 2020 SCE entered into settlements with individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation under which it agreed to pay an aggregate of approximately $300 million to those individual plaintiffs. Between December 31, 2020 and February 18, 2021, SCE also entered into settlements with individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation under which it agreed to pay an aggregate of approximately $80 million to those individual plaintiffs.

Edison International and SCE did not admit wrongdoing or liability as part of any of the settlements described above.

Other claims and potential claims related to the 2017/2018 Wildfire/Mudslide Events remain. SCE continues to explore reasonable settlement opportunities with other plaintiffs in the outstanding 2017/2018 Wildfire/Mudslide Events litigation.

Loss Estimates for Third Party Claims and Potential Recoveries from Insurance and through Electric Rates

At December 31, 2019, Edison International and SCE were unable to determine a best estimate of expected losses within a reasonably estimated range and therefore Edison International's and SCE's balance sheets included estimated losses, established at the lower end of the reasonably estimated range of expected losses, of $4.5 billion for the 2017/2018 Wildfire/Mudslide Events. In light of the TKM Subrogation Settlement and increased settlement activity with individual plaintiffs in the 2017/2018 Wildfire/Mudslide Events litigation, among other things, management established a best estimate of expected potential losses for alleged and potential claims related to the 2017/2018 Wildfire/Mudslide Events litigation in the third quarter of 2020. As a result, Edison International and SCE recorded a charge of $1.3 billion in September 2020 related to the 2017/2018 Wildfire/Mudslide Events, against which SCE recorded expected recoveries through FERC electric rates of $84 million. The resulting net pre-tax charge to earnings was $1.2 billion ($874 million after-tax).

At December 31, 2020 and December 31, 2019, Edison International's and SCE's balance sheets include accrued estimated losses of $4.4 billion and $4.5 billion, respectively, for the 2017/2018 Wildfire/Mudslide Events. The following table presents changes in estimated losses since December 31, 2019:

(in millions)		
Loss estimate balance at December 31, 2019	$	4,541
Increase in accrued estimated losses to reflect best estimate		1,297
Amounts paid		(1,455)
Loss estimate balance at December 31, 2020[1]		4,383

1 At December 31, 2020, $2,231 million in current liabilities, wildfire-related claims, on Edison International's and SCE's balance sheets includes an estimate for claims brought by insurance subrogation plaintiffs in the Woolsey Fire litigation, which were subsequently settled on January 22, 2021 for $2,212 million, and $19 million of other settlements executed in connection with the 2017/2018 Wildfire/Mudslide Events. At December 31, 2020, the $2,281 million included in deferred credits and other liabilities, wildfire-related claims on Edison International's and SCE's balance sheets includes Edison International and SCE's best estimate of expected losses for remaining alleged and potential claims related to the 2017/2018 Wildfire/Mudslide Events after giving effect to the Woolsey Subrogation Settlement of $2,152 million and other wildfire-related claims estimates of $129 million.

For the years-ended December 31, 2020 and 2019, SCE's statements of income include charges for the estimated losses, net of expected recoveries from insurance and FERC customers, related to the 2017/2018 Wildfire/Mudslide Events as follows:

	Year ended December 31,	
(in millions)	2020	2019
Charge for wildfire-related claims	$ 1,297	$ 232
Expected revenue from FERC customers	(84)	(14)
Total pre-tax charge	1,213	218
Income tax benefit	(339)	(61)
Total after-tax charge	$ 874	$ 157

For events that occurred in 2017 and early 2018, principally the Thomas and Koenigstein Fires and Montecito Mudslides, SCE had $1.0 billion of wildfire-specific insurance coverage, subject to a self-insured retention of $10 million per occurrence. For the Woolsey Fire, SCE had an additional $1.0 billion of wildfire-specific insurance coverage, subject to a self-insured retention of $10 million per occurrence. Edison International and SCE record a receivable for insurance recoveries when recovery of a recorded loss is determined to be probable. The following table presents changes in expected insurance recoveries associated with the estimated losses for the 2017/2018 Wildfire/Mudslide Events since December 31, 2019:

(in millions)	
Balance at December 31, 2019[1]	$ 1,710
Insurance recoveries	(1,002)
Balance at December 31, 2020	$ 708

1 At December 31, 2019, the balance was included in "Other long-term assets" on the balance sheets of SCE and Edison International.

At December 31, 2020, SCE had no remaining expected recoveries from insurance for the Thomas Fire, Koenigstein Fire and Montecito Mudslides litigation. At December 31, 2020, SCE had approximately $708 million remaining in expected recoveries from insurance for the Woolsey Fire litigation, included in "Insurance receivable" and "Insurance receivable from affiliate" on the balance sheets of SCE. SCE expects that this insurance will be exhausted after expected recoveries for the Woolsey Subrogation Settlement.

In total, SCE has accrued estimated losses of $6.2 billion, has paid or agreed to pay $4.1 billion in settlements and has recovered $1.3 billion, and has approximately $708 million remaining in expected recoveries, from its insurance carriers through February 18, 2021 in relation to the 2017/2018 Wildfire/Mudslide Events.

Recovery of SCE's actual losses realized in connection with the 2017/2018 Wildfire/Mudslide Events in excess of available insurance is subject to approval by regulators. Under accounting standards for rate-regulated enterprises, SCE defers costs as regulatory assets when it concludes that such costs are probable of future recovery in electric rates. SCE utilizes objectively determinable evidence to form its view on probability of future recovery. The only directly comparable precedent in which a California investor-owned utility has sought recovery for uninsured wildfire-related costs is SDG&E's requests for cost recovery related to 2007 wildfire activity, where the FERC allowed recovery of all FERC-jurisdictional wildfire-related costs while the CPUC rejected recovery of all CPUC-jurisdictional wildfire-related costs based on a determination that SDG&E did not meet the CPUC's prudency standard. As a result, while SCE does not agree with the CPUC's decision, it believes that the CPUC's interpretation and application of the prudency standard to SDG&E creates substantial uncertainty regarding how that standard will be applied to an investor-owned utility in future wildfire cost-recovery proceedings for fires ignited prior to July 12, 2019. SCE will continue to evaluate the probability of recovery based on available evidence, including judicial, legislative and regulatory decisions, including any CPUC decisions illustrating the interpretation and/or application of the prudency standard when making determinations regarding recovery of uninsured wildfire-related costs. While the CPUC has not made a determination regarding SCE's prudency relative to any of the 2017/2018 Wildfire/Mudslide Events, SCE is unable to conclude, at this time, that uninsured CPUC-jurisdictional wildfire-related costs are probable of recovery through electric rates. SCE would record a regulatory asset at the time it obtains sufficient information to support a conclusion that recovery is probable. SCE will seek CPUC-jurisdictional rate recovery of prudently-incurred, actual losses realized in connection with the 2017/2018 Wildfire/Mudslide Events in excess of available insurance.

SCE will seek recovery of the CPUC portion of any uninsured wildfire-related costs through its WEMA or its CEMA. In July 2019, SCE filed a CEMA application with the CPUC to seek recovery of, among other things, approximately $6 million in costs incurred to restore service to customers and to repair, replace and restore buildings and SCE's facilities damaged or destroyed as a result of the Thomas and Koenigstein Fires. SCE continues to incur costs for reconstructing its system and restoring service to structures that were damaged or destroyed by these two fires and plans to file additional applications with the CPUC to recover such costs. See "Recovery of Wildfire-Related Costs" below.

Through the operation of its FERC Formula Rate, and based upon the precedent established in SDG&E's recovery of FERC-jurisdictional wildfire-related costs, SCE believes it is probable it will recover its FERC-jurisdictional wildfire and mudslide related costs and has recorded total expected recoveries of $233 million within the FERC balancing account. This was the FERC portion of the estimated losses accrued. As of December 31, 2020, collections have reduced the regulatory assets remaining in the FERC balancing account to $89 million.

Current Wildfire Insurance Coverage

SCE had approximately $1.2 billion of wildfire-specific insurance coverage for events that occurred during the period June 1, 2019 through June 30, 2020, subject to up to $115 million of co-insurance and $50 million of self-insured retention, which resulted in net coverage of approximately $1.0 billion. SCE has approximately $1.0 billion of wildfire-specific insurance coverage for events that may occur during the period July 1, 2020 through June 30, 2021, subject to up to $80 million of co-insurance and $50 million of self-insured retention, which results in net coverage of approximately $870 million. Various coverage limitations within the policies that make up SCE's wildfire insurance coverage could result in additional material self-insured costs, for instance in the event of multiple wildfire occurrences during a policy period. SCE believes that its insurance coverage for the July 1, 2020 through June 30, 2021 period meets its obligation to maintain reasonable insurance coverage under AB 1054.

Wildfire insurance expense in 2020, prior to any regulatory deferrals, was approximately $450 million. Wildfire insurance expense in 2019, prior to any regulatory deferrals, was approximately $400 million. Calendar year insurance expense reflects the portion of premiums attributable to policy coverage in that calendar year.

SCE tracks incremental insurance premium, self-insured retention and co-insurance costs related to wildfire liability insurance policies as well as other wildfire-related costs, including claims and legal costs, in its WEMA. In July 2019, SCE filed a WEMA application with the CPUC to seek recovery of an aggregate of $505 million, consisting of $478 million in wildfire insurance premium costs that had been incurred or were to be incurred before July 1, 2020 in excess of premiums approved in the 2018 GRC and the corresponding financing costs. In September 2020, the CPUC approved SCE's July 2019 WEMA application and authorized SCE to collect a total revenue requirement of $505 million over a two-year period. SCE included the authorized revenue requirement in rates in October 2020. In December 2020, SCE filed another WEMA application with the CPUC to seek recovery of an aggregate of $214 million, consisting of $204 million in wildfire insurance premium costs in excess of premiums approved in the 2018 GRC, representing wildfire insurance premiums for July 1, 2020 through December 31, 2020, the corresponding financing costs, memorandum account interest and a prior period premium adjustment.

SCE's cost of obtaining wildfire insurance coverage has increased significantly in recent years as a result of, among other things, the number of recent and significant wildfire events throughout California and the application of inverse condemnation to investor-owned utilities. As such, while SCE is required to maintain reasonable insurance coverage under AB 1054, SCE may not be able to obtain a reasonable amount of wildfire insurance, at a reasonable cost, for future policy periods.

Recovery of Wildfire-Related Costs

Pre-AB 1054 Cost Recovery

California courts have previously found investor-owned utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. The rationale stated by these courts for applying this theory to investor-owned utilities is that property damages resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement through recovery of uninsured wildfire-related costs in electric rates. However, in November 2017, the CPUC issued a decision denying SDG&E's request to include in its rates uninsured wildfire-related costs arising from several 2007 wildfires, finding that SDG&E did not meet the prudency standard because it did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires. In July 2018, the CPUC denied both SDG&E's application for rehearing on its cost recovery request and a joint application for rehearing filed by SCE and PG&E limited to the applicability of inverse condemnation principles in the same proceeding. The California Court of Appeal, the California Supreme Court and the United States Supreme Court have denied SDG&E's petitions for review of the CPUC's denial of SDG&E's application.

2019 Wildfire Legislation

In July 2019, AB 1054 was signed by the governor of California and became effective immediately. The summary of the wildfire legislation below is based on SCE's interpretation of AB 1054. A lawsuit challenging the validity of AB 1054 was filed in federal court on July 19, 2019. Edison International and SCE are unable to predict the outcome of this lawsuit.

AB 1054 Prudency Standard

Under AB 1054, the CPUC must apply a new standard when assessing the prudency of a utility in connection with a request for recovery of wildfire costs for wildfires ignited after July 12, 2019. Under AB 1054, the CPUC is required to find a utility to be prudent if the utility's conduct related to the ignition was consistent with actions that a reasonable utility would have undertaken under similar circumstances, at the relevant point in time, and based on the information available at that time. Prudent conduct under the AB 1054 standard is not limited to the optimum practice, method, or act to the exclusion of others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with utility system needs, the interest of the ratepayers, and the requirements of governmental agencies. AB 1054 also provides that the CPUC may determine that wildfire costs may be recoverable, in whole or in part, by taking into account factors within and outside the utility's control, including humidity, temperature, and winds. Further, utilities with a valid safety certification will be presumed to have acted prudently related to a wildfire ignition unless a party in the cost recovery proceeding creates serious doubt as to the reasonableness of the utility's conduct, at which time, the burden shifts back to the utility to prove its conduct was reasonable. If a utility does not have a valid safety certification, it will have the burden to prove, based on a preponderance of evidence, that its conduct was prudent. The new prudency standard will survive the termination of the Wildfire Insurance Fund.

Utilities participating in the Wildfire Insurance Fund are not required to reimburse the fund for amounts withdrawn from the fund that the CPUC finds were prudently incurred and can recover such prudently incurred wildfire costs through electric rates if the fund has been exhausted.

Wildfire Insurance Fund

AB 1054 provided for the Wildfire Insurance Fund to reimburse a utility for payment of third-party damage claims arising from certain wildfires that exceed, in aggregate in a calendar year, the greater of $1.0 billion or the insurance coverage required to be maintained under AB 1054. The Wildfire Insurance Fund was established in September 2019 and is available for claims related to wildfires ignited after July 12, 2019 that are determined by the responsible government investigatory agency to have been caused by a utility.

SCE and SDG&E collectively made their initial contributions totaling approximately $2.7 billion to the Wildfire Insurance Fund in September 2019. Upon its emergence from bankruptcy, on July 1, 2020, PG&E made its initial contribution of approximately $4.8 billion to the Wildfire Insurance Fund. PG&E, SCE and SDG&E are also collectively expected to make aggregate contributions of approximately $3.0 billion to the Wildfire Insurance Fund through annual contributions to the fund over a 10-year period, of which they have made two annual contributions totaling approximately $600 million. In addition to PG&E's, SCE's and SDG&E's contributions to the Wildfire Insurance Fund, PG&E, SCE and SDG&E are expected to collect $6.1 billion, $6.1 billion and $1.3 billion, respectively, from their customers over a 15-year period through a dedicated rate component. The amount collected from customers may be directly contributed to the Wildfire Insurance Fund or used to support the issuance of up to $10.5 billion in bonds by the California Department of Water Resources, the proceeds of which would be contributed to the fund. In addition to funding contributions to the Wildfire Insurance Fund, the amount collected from utility customers will pay for, among other things, any interest and financing costs related to any bonds that are issued by the California Department of Water Resources to support the contributions to the Wildfire Insurance Fund.

SCE made an initial contribution of approximately $2.4 billion to the Wildfire Insurance Fund in September 2019 and committed to make ten annual contributions of approximately $95 million per year to the fund, by no later than January 1 of each year. Through December 31, 2020, SCE has contributed approximately $2.6 billion to the Wildfire Insurance Fund. During 2020 SCE amortized its contributions to the Wildfire Insurance Fund over 10 years, based on evaluation of the fund's expected life based on actual fire experience to December 31, 2020. SCE expects the life of the fund to be 15 years from July 12, 2019 which will be reflected prospectively in amortization expense from January 1, 2021. SCE's contributions to the Wildfire Insurance Fund will not be recoverable through electric rates and will be excluded from the measurement of SCE's CPUC-jurisdictional authorized capital structure. SCE will also not be entitled to cost recovery for any borrowing costs incurred in connection with its contributions to the Wildfire Insurance Fund. See Note 1 for information on the accounting impact of SCE's contributions to the Wildfire Insurance Fund.

Reimbursement from Wildfire Insurance Fund and AB 1054 Liability Cap

Participating investor-owned utilities will be reimbursed from the Wildfire Insurance Fund for eligible claims, subject to the fund administrator's review. SCE will reimburse the fund for any withdrawn amounts if SCE receives payment of such amounts under an indemnification agreement or from an insurance provider or other third-party. SCE will also be required to reimburse the fund for withdrawn amounts that the CPUC disallows, subject, in some instances, to the AB 1054 Liability Cap (as defined below). If the utility has maintained a valid safety certification and its actions or inactions that resulted in the wildfire are not found to constitute conscious or willful disregard of the rights and safety of others, the aggregate requirement to reimburse the fund over a trailing three calendar year period is capped at 20% of the equity portion of the utility's transmission and distribution rate base in the year of the prudency determination ("AB 1054 Liability Cap"). Based on SCE's forecasted weighted-average 2021 rate base and using the equity portion of SCE's CPUC authorized capital structure of 52%, SCE's requirement to reimburse the Wildfire Insurance Fund for eligible claims disallowed in 2021 would be capped at approximately $3.2 billion.

SCE will not be allowed to recover borrowing costs incurred to reimburse the fund for amounts that the CPUC disallows. The Wildfire Insurance Fund and, consequently, the AB 1054 Liability Cap will terminate when the administrator determines that the fund has been exhausted.

Safety Certification and Wildfire Mitigation Plan

Under AB 1054, SCE can obtain an annual safety certification upon the submission of certain required safety information, including an approved wildfire mitigation plan ("WMP"). On September 17, 2020, SCE obtained a safety certification that will be valid for 12 months. Notwithstanding its 12-month term, if SCE requests a new safety certification prior to the expiration of its current safety certification, then its current safety certification will remain valid until the CPUC's Wildfire Safety Division ("WSD") acts on SCE's request for a new safety certification.

Under AB 1054, SCE is required to submit a WMP to the CPUC at least once every three years for review and approval. Beginning in 2020, each such plan was required to cover at least a three-year period. SCE filed its 2020 – 2022 WMP in February 2020. In June 2020 the CPUC ratified the WSD's conditional approval of SCE's 2020 – 2022 WMP. The approval is conditioned on SCE providing requested information to the WSD, including additional descriptions of how SCE is implementing, and will implement, certain requirements imposed by the WSD. SCE filed an update to its 2020 – 2022 WMP on February 5, 2021 to, among other things, report on implementation of its plan in 2020 and describe new and ongoing wildfire mitigation activities.

Capital Expenditure Requirement

Under AB 1054, approximately $1.6 billion of spending by SCE on wildfire risk mitigation capital expenditures made after August 1, 2019, cannot be included in the equity portion of SCE's rate base ("AB 1054 Excluded Capital Expenditures"). SCE can apply for irrevocable orders from the CPUC to finance these AB 1054 Excluded Capital Expenditures, including through the issuance of securitized bonds, and can recover any prudently incurred financing costs. In November 2020, the CPUC issued an irrevocable order permitting SCE to finance approximately $340 million, comprised of AB 1054 Excluded Capital Expenditures incurred in connection with GS&RP and prudently incurred financing costs, through the issuance of securitized bonds. As of December 31, 2020, SCE has spent $1.3 billion on AB 1054 Excluded Capital Expenditures and expects to spend the remainder of the AB 1054 Excluded Capital Expenditures in the first quarter of 2021. SCE issued securitized bonds in the amount of $338 million in February 2021 and expects to seek additional irrevocable orders from the CPUC to finance the remaining AB 1054 Excluded Capital Expenditures.

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 (reflected in "Other long-term liabilities") at undiscounted amounts as timing of cash flows is uncertain.

At December 31, 2020, SCE's recorded estimated minimum liability to remediate its 25 identified material sites (sites with a liability balance as of December 31, 2020, in which the upper end of the range of the costs is at least $1 million) was $255 million, including $173 million related to San Onofre. In addition to these sites, SCE also has 15 immaterial sites with a liability balance at December 31, 2020 for which the total minimum recorded liability was $4 million. Of the $259 million total environmental remediation liability for SCE, $247 million has been recorded as a regulatory asset. SCE expects to recover $40 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 in this mechanism), and $207 million through proceedings that allow SCE to recover up to 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.

SCE performed 1.6 miles of access road grading and vegetation clearing in the Mission Canyon area of Santa Barbara County in December 2019, resulting in debris moving downslope into a creek bed and other impacts in the area (the "Mission Canyon Incident"). Several state and federal environmental agencies and the County and City of Santa Barbara have investigated the unpermitted grading and discharges to the creek, and SCE has received Notices of Violation from the Army Corps of Engineers, the County of Santa Barbara, the California Department of Fish & Wildlife and the Regional Water Quality Control Board. In December 2020, SCE and the Santa Barbara County District Attorney entered into a settlement regarding alleged criminal and civil violations related to the Mission Canyon Incident. Under the settlement, SCE pled no contest to a single misdemeanor charge for violation of the California Water Code and agreed to pay a $10,000 fine. SCE also agreed to pay a civil penalty of $3.5 million and is subject to an injunction compelling it to complete planned remediation work related to the Mission Canyon Incident and not commit similar violations for five years. It is presently unknown whether any other regulatory agencies will impose fines or penalties on SCE with respect to the Mission Canyon Incident and, if so, in what amounts. SCE does not expect fines or penalties that are imposed in connection with the Mission Canyon Incident to be material. As of December 31, 2020, SCE recorded $8 million of estimated minimum liability in relation to the Mission Canyon Incident, primarily associated with environmental remediation. Costs incurred for the year ended December 31, 2020 Mission Canyon Incident was approximately $7 million. SCE will not seek recovery of these costs from customers in rates.

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 $122 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. The ultimate costs to remediate the Mission Canyon Incident is currently not estimable.

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 5 years are expected to range from $9 million to $20 million. Costs incurred for years ended December 31, 2020, 2019 and 2018 were $7 million, $9 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 $13.8 billion for Palo Verde and $560 million for San Onofre. As of

January 1, 2020, SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($450 million) through a Facility Form issued by American Nuclear Insurers ("ANI"). In the case of San Onofre, the balance is covered by a US Government indemnity. In the case of Palo Verde, 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, which is participating in the loss sharing program, results in claims and/or costs which exceed the primary insurance at that plant site, all participating 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 the nuclear energy hazard at San Onofre or Palo Verde, or while radioactive material is in transit to or from San Onofre or Palo Verde. 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 Nuclear Electric Insurance Limited ("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 $450 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.

SCE withdrew from participation in the secondary insurance pool for San Onofre for offsite liability insurance effective January 5, 2018. Based on its ownership interests in Palo Verde, SCE could be required to pay a maximum of approximately $65 million per nuclear incident for future incidents. However, it would have to pay no more than approximately $10 million per future incident in any one year. SCE could be required to pay a maximum of approximately $255 million per nuclear incident and a maximum of $38 million per year per incident for liabilities arising from events prior to January 5, 2018, although SCE is not aware of any such events. 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.

SCE is a member of NEIL, a mutual insurance company owned by entities with nuclear facilities. NEIL provides insurance for nuclear property damage, including damages caused by acts of terrorism up to specified limits, and for accidental outages for active facilities. The amount of nuclear property damage insurance purchased for San Onofre and Palo Verde exceeds the minimum federal requirement of $50 million and $1.1 billion, respectively. These policies include coverage for decontamination liability. 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 NEIL 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 $30 million per year. Insurance premiums are charged to operating expense (FERC account 924).

Spent Nuclear Fuel

Under federal law, the 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 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. In April 2016, SCE, as operating agent, settled a lawsuit on behalf of the San Onofre owners against the DOE for $162 million (SCE share $124 million, which included reimbursement for approximately $2 million in legal and other costs), to compensate for damages caused by 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. In August 2018, the CPUC approved SCE's proposal to return the SCE share of the award to customers based on the amount that customers actually contributed for fuel storage costs; resulting in approximately $106 million of the SCE share being returned to customers and the remaining $17 million being returned to shareholders. Of the $106 million, $72 million was applied against the remaining San Onofre Regulatory Asset in accordance with the Revised San Onofre Settlement Agreement.

The April 2016 settlement also provided for a claim submission/audit process for expenses incurred from 2014 – 2016, where SCE may submit a claim for damages caused by the DOE failure to accept spent nuclear fuel each year, followed by a government audit and payment of the claim. This process made additional legal action to recover damages incurred in 2014 – 2016 unnecessary. The first such claim covering damages for 2014 – 2015 was filed on September 30, 2016 for approximately $56 million. In February 2017, the DOE reviewed the 2014 – 2015 claim submission and reduced the original request to approximately $43 million (SCE share was approximately $34 million). SCE accepted the DOE's determination, and the government paid the 2014 – 2015 claim under the terms of the settlement. In October 2017, SCE filed a claim covering damages for 2016 for approximately $58 million. In May 2018, the DOE approved reimbursement of approximately $45 million (SCE share was approximately $35 million) of SCE's 2016 damages, disallowing recovery of approximately $13 million. SCE accepted the DOE's determination, and the government paid the 2016 claim under the terms of the settlement. The damages awards are subject to CPUC review as to how the amounts will be refunded among customers, shareholders, or to offset other costs.

In November 2019, SCE filed a new complaint against the DOE to recover damages incurred from January 1, 2017 through July 31, 2018.

Upstream Lighting Program

From 2017 – 2019, SCE administered the Upstream Lighting Program, part of a statewide program administered by investor-owned utilities that offered discounted energy efficient light bulbs to customers through incentives to lighting manufacturers. The CPUC began investigating the programs administered by the investor-owned utilities based on reports that investor-owned utilities, including SCE, shipped a significant number of bulbs under the program that could not be tracked to customers. Beginning in January 2020, the CPUC has sought comments on remedies related to SCE's implementation of the Upstream Lighting Program from 2017 through 2019 program years. SCE undertook an independent investigation of bulbs shipped to retailers categorized as grocery and discount businesses during the 2017 to 2019 program years and found that there were overstocking of bulbs and program management shortcomings. Incentives paid to manufacturers for bulbs shipped to grocery and discount businesses during the relevant period, including those that were sold to customers, were approximately $91 million. In addition, SCE received incentives related to the bulbs shipped to grocery and discount businesses through an energy efficiency incentive mechanism ("ESPI Mechanism") of approximately $3.5 million related to the bulbs shipped in 2017 and 2018. SCE also expects to receive incentives of approximately $1.3 million under the ESPI Mechanism in 2022 related to bulbs shipped to grocery and discount businesses in 2018 and 2019. In January 2021, the Public Advocates Office and The Utility Reform Network provided comments to the CPUC arguing that SCE imprudently managed the program and requesting: a refund of $33 million of ESPI awards, which includes incentives associated with the Upstream Lighting Program and other energy efficiency programs; a refund of $92 million of incentives paid to manufacturers and associated program administrative costs; $140 million in fines; and additional program improvements to be provided at shareholder expense. SCE has accrued a charge for potential losses relating to the Upstream Lighting Program. The accrued charge corresponds to the lower end of the reasonably estimated range of expected losses that may be incurred in connection with the Upstream Lighting Program and is subject to change as additional information becomes available.

ITEM 3. UTILITY PLANT RESTRICTIONS

N/A

ITEM 4. RATE TREATMENT WHERE UNAMORTIZED LOSS ON REACQUIRED DEBT AND UNAMORTIZED GAIN ON REACQUIRED DEBT ACCOUNTS ARE NOT USED.

These accounts are used where applicable. The balance for unamortized loss on reacquired debt (account number 189) at December 31, 2020 was approximately $133 million. There was no unamortized gain (account number 257) recorded at December 31, 2020.

ITEM 5. RETAINED EARNINGS RESTRICTIONS

CPUC holding company rules require that SCE's dividend policy be established by SCE's Board of Directors on the same basis as if SCE were a stand-alone utility company, and that the capital requirements of SCE, as deemed to be necessary to meet SCE's electricity service obligations, shall receive first priority from the Boards of Directors of both Edison International and SCE. In addition, the CPUC regulates SCE's capital structure which limits the dividends it may pay to its shareholders.

Effective January 1, 2020, the common equity component of SCE's CPUC authorized capital structure was increased from 48% to 52% on a weighted average basis over the January 1, 2020 to December 31, 2022 compliance period. Under AB 1054, the impact of SCE's contributions to the Wildfire Insurance Fund are excluded from the measurement of SCE's CPUC-jurisdictional authorized capital structure. For further information, see Note 12.

In May 2020, the CPUC issued a decision on SCE's application to the CPUC for waiver of compliance with its equity ratio requirement, that allows SCE to exclude from its equity ratio calculations (i) net charges accrued in connection with the 2017/2018 Wildfire/Mudslide Events and (ii) debt issued for the purpose of paying claims related to the 2017/2018 Wildfire/Mudslide Events up to an amount equal to the net charges accrued in connection with the 2017/2018 Wildfire/Mudslide Events. The temporary exclusion will lapse on May 7, 2022 or when a determination regarding cost recovery for the 2017/2018 Wildfire/Mudslide Events is made, whichever comes earlier. If the CPUC has not made a determination regarding cost recovery by May 7, 2022, SCE is permitted to file another application for a waiver of compliance with its equity ratio requirement. In the interim, SCE is required to notify the CPUC if an adverse financial event reduces SCE's spot equity ratio by more than one percent from the level most recently filed with the CPUC in the proceeding. The last spot equity ratio SCE filed with the CPUC in the proceeding did not exclude the then $1.8 billion net charge and was 45.2% as of December 31, 2018 (at the time the common equity component of SCE's CPUC authorized capital structure was required to remain at or above 48% on a weighted average basis over the applicable 37-month period). SCE's spot equity ratio on December 31, 2018 would have been 48.7% had the $1.8 billion net charge at December 31, 2018 been excluded, therefore SCE will notify the CPUC if its spot ratio drops below 47.7% in any quarter. For further information, see Note 12.

SCE monitors its compliance with the CPUC's equity ratio requirement based on the weighted average of the common equity component of SCE's CPUC authorized capital structure over the Capital Structure Compliance Period using its actual capital structure from the beginning of the Capital Structure Compliance Period through the reporting date together with forecasted performance and expected financing activities for the remainder of the Capital Structure Compliance Period. SCE expects to be compliant with its CPUC authorized capital structure at December 31, 2022.

As a California corporation, SCE's ability to pay dividends is also governed by the California General Corporation Law. California law requires that for a dividend to be declared: (a) retained earnings must equal or exceed the proposed dividend, or (b) immediately after the dividend is made, the value of the corporation's assets must exceed the value of its liabilities plus amounts required to be paid, if any, in order to liquidate stock senior to the shares receiving the dividend. Additionally, a California corporation may not declare a dividend if it is, or as a result of the dividend would be, likely to be unable to meet its liabilities as they mature. Prior to declaring dividends, SCE's Board of Directors evaluates available information, including when applicable, information pertaining to the 2017/2018 Wildfire/Mudslide Events, to ensure that the California law requirements for the declarations are met. On February 25, 2021, SCE declared a dividend to Edison International of $325 million.

The timing and amount of future dividends are also dependent on a number of other factors including SCE's requirements to fund other obligations and capital expenditures, its ability to access the capital markets, and generate operating cash flows and earnings. If SCE incurs significant costs related to catastrophic wildfires, including the 2017/2018 Wildfire/Mudslide Events, and is unable to recover such costs through insurance, the Wildfire Insurance Fund (for fires after July 12, 2019), or from customers or is unable to access capital markets on reasonable terms, SCE may be limited in its ability to pay future dividends to Edison International and its preference shareholders.

ITEM 6. ADDITIONAL NOTES TO FINANCIAL STATEMENTS

See responses to Items 1 and 2 above.

ITEM 7. INTERIM DISCLOSURES

See responses to Items 1 and 2 above.

ITEM 8. SUBSEQUENT EVENTS

See responses to Items 1 and 2 above.

ITEM 9. APPLICABLE NOTES

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	04/14/2021	End of 2020/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				(22,574,194)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				3,265,186
3	Preceding Quarter/Year to Date Changes in Fair Value				(19,502,862)
4	Total (lines 2 and 3)				(16,237,676)
5	Balance of Account 219 at End of Preceding Quarter/Year				(38,811,870)
6	Balance of Account 219 at Beginning of Current Year				(38,811,870)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				4,823,057
8	Current Quarter/Year to Date Changes in Fair Value				(6,803,049)
9	Total (lines 7 and 8)				(1,979,992)
10	Balance of Account 219 at End of Current Quarter/Year				(40,791,862)

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			(22,574,194)	[redacted]	[redacted]
2			3,265,186	[redacted]	[redacted]
3			(19,502,862)	[redacted]	[redacted]
4			(16,237,676)	1,529,711,729	1,513,474,053
5			(38,811,870)	[redacted]	[redacted]
6			(38,811,870)	[redacted]	[redacted]
7			4,823,057	[redacted]	[redacted]
8			(6,803,049)	[redacted]	[redacted]
9			(1,979,992)	942,385,439	940,405,447
10			(40,791,862)	[redacted]	[redacted]

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	04/14/2021	End of 2020/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)	51,097,410,949	51,049,265,502
4	Property Under Capital Leases	1,119,661,082	1,119,661,082
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,512,879,974	3,512,879,974
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	55,729,952,005	55,681,806,558
9	Leased to Others		
10	Held for Future Use	30,786,584	30,786,584
11	Construction Work in Progress	5,032,910,818	5,026,944,132
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	60,793,649,407	60,739,537,274
14	Accum Prov for Depr, Amort, & Depl	14,781,425,486	14,753,784,803
15	Net Utility Plant (13 less 14)	46,012,223,921	45,985,752,471
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	14,105,692,786	14,078,052,103
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	675,732,700	675,732,700
22	Total In Service (18 thru 21)	14,781,425,486	14,753,784,803
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)	14,781,425,486	14,753,784,803

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	04/14/2021	End of 2020/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
6,489,458	40,655,488			1,000,501	3
					4
					5
					6
					7
6,489,458	40,655,488			1,000,501	8
					9
					10
339,097	5,627,589				11
					12
6,828,555	46,283,077			1,000,501	13
2,445,473	24,594,178			601,032	14
4,383,082	21,688,899			399,469	15
					16
					17
2,445,473	24,594,178			601,032	18
					19
					20
					21
2,445,473	24,594,178			601,032	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
2,445,473	24,594,178			601,032	33

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

Effective 1/1/19, SCE adopted Accounting Standards Updates requiring lessees to recognize leases on the balance sheet as right-of-use assets and related lease liabilities. SCE has elected to report these leases in the FERC balance sheet using accounts established for capital leases.

For Utility Plant (Account 101.1), the reported right-of-use assets of $1,119,661,082 which includes $1,084,940,623 operating leases, $3,561,152 capital leases and $31,159,307 power purchase financing agreements.

For further information, see Notes to Financial Statements included on page 122-123.

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	04/14/2021	End of 2020/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	65,572,514	33,688,137
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	65,572,514	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	168,909,284	34,797,470
10	SUBTOTAL (Total 8 & 9)	168,909,284	
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)	105,961,809	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	128,519,989	
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
	34,797,469	64,463,182	3
			4
			5
		64,463,182	6
			7
			8
	19,255,596	184,451,158	9
		184,451,158	10
			11
			12
-30,805,774	19,255,596	117,511,987	13
		131,402,353	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 (Account 120.1 - $34,797,469)

Schedule Page: 202   Line No.: 9   Column: e
Retired fully amortized batch. (Account 120.3 and Account 120.5 - $19,255,596)

Schedule Page: 202   Line No.: 13   Column: e
Retired fully amortized batch. (Account 120.3 and Account 120.5 - $19,255,596)

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	2,948,240	
3	(302) Franchises and Consents	160,892,408	9,340,548
4	(303) Miscellaneous Intangible Plant	1,089,986,823	392,823,245
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,253,827,471	402,163,793
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	255,828	
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	255,828	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,935,457	
19	(321) Structures and Improvements	646,955,952	14,444,752
20	(322) Reactor Plant Equipment	744,684,519	15,563,932
21	(323) Turbogenerator Units	287,749,935	7,645,161
22	(324) Accessory Electric Equipment	197,588,373	1,441,572
23	(325) Misc. Power Plant Equipment	154,074,993	4,378,831
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,032,989,229	43,474,248
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	4,977,461	
28	(331) Structures and Improvements	233,744,969	4,852,353
29	(332) Reservoirs, Dams, and Waterways	605,937,991	16,002,893
30	(333) Water Wheels, Turbines, and Generators	199,258,115	210,526
31	(334) Accessory Electric Equipment	226,217,587	3,346,363
32	(335) Misc. Power PLant Equipment	13,737,828	
33	(336) Roads, Railroads, and Bridges	20,848,394	4,865,601
34	(337) Asset Retirement Costs for Hydraulic Production	7,077,910	3,181,202
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,311,800,255	32,458,938
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,745,317	
38	(341) Structures and Improvements	103,932,500	631,576
39	(342) Fuel Holders, Products, and Accessories	16,537,472	
40	(343) Prime Movers	1,206,543,486	1,922,867
41	(344) Generators	119,849,939	
42	(345) Accessory Electric Equipment	208,570,753	-903,796
43	(346) Misc. Power Plant Equipment	114,653,896	1,140,670
44	(347) Asset Retirement Costs for Other Production	39,345,139	5,138,692
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,813,178,502	7,930,009
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,158,223,814	83,863,195

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	345,076,489	1,987,268
49	(352) Structures and Improvements	1,143,959,578	111,173,134
50	(353) Station Equipment	6,517,444,414	497,821,856
51	(354) Towers and Fixtures	2,380,316,641	16,485,126
52	(355) Poles and Fixtures	1,666,864,455	193,835,747
53	(356) Overhead Conductors and Devices	1,763,812,033	128,842,322
54	(357) Underground Conduit	296,662,316	28,771,530
55	(358) Underground Conductors and Devices	376,202,208	33,027,962
56	(359) Roads and Trails	201,604,232	14,241,040
57	(359.1) Asset Retirement Costs for Transmission Plant	9,010,624	6,968,715
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	14,700,952,990	1,033,154,700
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	129,043,959	7,857,325
61	(361) Structures and Improvements	799,384,569	52,835,780
62	(362) Station Equipment	2,967,456,409	165,992,104
63	(363) Storage Battery Equipment	707	6,895,792
64	(364) Poles, Towers, and Fixtures	3,580,688,076	343,477,229
65	(365) Overhead Conductors and Devices	2,100,921,150	342,969,176
66	(366) Underground Conduit	2,605,989,597	241,347,337
67	(367) Underground Conductors and Devices	6,711,323,168	259,418,281
68	(368) Line Transformers	4,572,833,795	414,127,240
69	(369) Services	1,587,271,265	103,381,942
70	(370) Meters	1,030,209,521	38,741,564
71	(371) Installations on Customer Premises	12,374,490	367,136
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	862,566,803	39,230,847
74	(374) Asset Retirement Costs for Distribution Plant	9,017,359	-468,134
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	26,969,080,868	2,016,173,619
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	30,051,064	
87	(390) Structures and Improvements	1,106,846,686	25,433,941
88	(391) Office Furniture and Equipment	807,470,606	153,459,423
89	(392) Transportation Equipment	20,886,697	3,807,251
90	(393) Stores Equipment	10,841,268	398,766
91	(394) Tools, Shop and Garage Equipment	87,831,771	6,745,918
92	(395) Laboratory Equipment	123,490,760	12,410,441
93	(396) Power Operated Equipment	856,947	
94	(397) Communication Equipment	994,554,416	121,761,431
95	(398) Miscellaneous Equipment	43,864,478	-2,827,088
96	SUBTOTAL (Enter Total of lines 86 thru 95)	3,226,694,693	321,190,083
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	12,163,140	5,124,378
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	3,238,857,833	326,314,461
100	TOTAL (Accounts 101 and 106)	51,320,942,976	3,861,669,768
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)	51,320,942,976	3,861,669,768

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	04/14/2021	End of 2020/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			2,948,240		2
			170,232,956		3
67,536,106		-1,449,361	1,413,824,601		4
67,536,106		-1,449,361	1,587,005,797		5
					6
					7
			255,828		8
					9
					10
					11
					12
					13
					14
					15
			255,828		16
					17
			1,935,457		18
2,122			661,398,582		19
			760,248,451		20
			295,395,096		21
			199,029,945		22
			158,453,824		23
					24
2,122			2,076,461,355		25
					26
			4,977,461		27
316,495			238,280,827		28
46,157			621,894,727		29
321,303			199,147,338		30
180,101			229,383,849		31
			13,737,828		32
			25,713,995		33
			10,259,112		34
864,056			1,343,395,137		35
					36
			3,745,317		37
2,121,157			102,442,919		38
			16,537,472		39
35,697,788		-385,043	1,172,383,522		40
			119,849,939		41
245,459		-297,467	207,124,031		42
		682,510	116,477,076		43
			44,483,831		44
38,064,404			1,783,044,107		45
38,930,582			5,203,156,427		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	04/14/2021	End of 2020/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
31,553			347,032,204		48
1,783,304		233,015	1,253,582,423		49
44,711,642		-103,762	6,970,450,866		50
263,246			2,396,538,521		51
32,668,937			1,828,031,265		52
1,155,616			1,891,498,739		53
212,674			325,221,172		54
3,082,586			406,147,584		55
7,466			215,837,806		56
			15,979,339		57
83,917,024		129,253	15,650,319,919		58
					59
11,686		-7,276,401	129,613,197		60
7,378,668		-228,151	844,613,530		61
26,581,974		97,233	3,106,963,772		62
		7,277,841	14,174,340		63
57,423,059			3,866,742,246		64
36,843,111			2,407,047,215		65
5,793,883			2,841,543,051		66
43,066,091			6,927,675,358		67
93,189,182			4,893,771,853		68
3,012,713			1,687,640,494		69
2,541,423			1,066,409,662		70
			12,741,626		71
					72
46,279,583			855,518,067		73
			8,549,225		74
322,121,373		-129,478	28,663,003,636		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-2,909,915	27,141,149		86
4,587,666			1,127,692,961		87
29,998,034		1,455,833	932,387,828		88
60,901			24,633,047		89
582,655		-6,473	10,650,906		90
8,959,776			85,617,913		91
4,207,574		225	131,693,852		92
			856,947		93
56,255,406			1,060,060,441		94
400,255			40,637,135		95
105,052,267		-1,460,330	3,441,372,179		96
					97
			17,287,518		98
105,052,267		-1,460,330	3,458,659,697		99
617,557,352		-2,909,916	54,562,145,476		100
					101
					102
					103
617,557,352		-2,909,916	54,562,145,476		104

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	04/14/2021	End of 2020/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	NONE.				
2					
3					
4					
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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	04/14/2021	End of 2020/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)			
6				
7				
8	360 - Land and Land Rights:			
9				
10				
11	Under $250,000 (3)			
12				
13				
14				
15	350 - Land and Land Rights:			
16				
17				
18	Over $250,000 (1) Alberhill 500Kv Line Substation	2011		15,781,292
19	Over $250,000 (2) Circle City Substation	2018		15,005,292
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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41				
42				
43				
44				
45				
46				
47	Total			30,786,584

Schedule Page: 214   Line No.: 18   Column: c

Pending CPUC Decision

Schedule Page: 214   Line No.: 19   Column: c

Pending determination of use.

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	04/14/2021	End of 2020/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	FIP-WOD 220 kV Trans Line Installat	561,847,335
3	CSRP - Back Office	249,794,956
4	50 STRM 2020-09-05T16:00:00Z-CEMA-	169,385,820
5	CSRP - Front Office	137,718,611
6	FIP-Mesa: Upgrade to a 500/230/66/1	122,968,414
7	CSRP - Foundational	118,745,364
8	51-STORM 09.13.2020 CASTLE FIRE	71,125,209
9	FIP-West of Devers Upgrade Project:	66,679,790
10	VA-4950-0353--IVYGLEN: BRING IN SEC	65,735,917
11	GM - Grid & DER Mgmt - Master	63,803,070
12	Devers Red Bluff No.1 TLRR 99 Disc	62,650,129
13	8065-5001--Alberhill: Licensing Pha	44,542,472
14	Big Creek 1-Rctr TLRR Remediation S	41,926,610
15	VA-CONSTRUCT APPROXIMATELY 12.5MILE	40,429,263
16	Moorpark-Pardee 4: String approx 25	34,510,990
17	GO1 Workplace Upgrade (Phase 1-7) -	32,943,808
18	GM - Field Area Network (FAN)	31,923,579
19	FIP-Lugo Sub: Upgrade Terminal Equi	25,939,023
20	GM - Gen Intercon App - Master	25,066,262
21	Lee Vining Sub: Rebuild Substation	24,602,748
22	PEFL Garnet-Rebuild 115/33kV swtrk,	23,070,922
23	FIP-Eldorado Substation: Upgrade Te	22,955,278
24	FIP-Mohave Substation: Install four	22,566,342
25	DH J.Shumaker/C.Hotta R/R 9 TRANS	22,441,674
26	Bobcat Fire Storm 090620	21,871,973
27	FIP-Ludlow Mid-Line Capacitor: Inst	21,197,379
28	FIP-Newberry Springs Mid-Line Capac	20,878,455
29	GMS Release 1.0 Implementation	17,141,879
30	Highgrove rebuild swtrack Add MEER(	17,095,783
31	CFF~Natural Sub: Phase 2- Construct	16,697,576
32	SD - AUD Refresh	16,691,049
33	GM - Grid Analytics App - R3.3 Mast	16,319,853
34	Lighthipe Sub: Switchrack Rebuild	16,073,442
35	Pardee-Pastoria 220kV-San Jq-TLRR	15,722,203
36	CS Re-platform Planning IOC	15,109,498
37	GM Cyber - Program Support	14,479,740
38	FIP-Mira Loma-Vista No. 1 220 kV T/	13,500,839
39	Devers Sub: Install (2) 56MVA trans	13,446,778
40	GO1 Seismic Upgrades (Phase 1-7) -	12,576,985
41	Tapia:Rebld66kVGIS+16kV swrk;replc	12,337,443
42	GM - Grid Connectivity Model - R3.5	12,202,811
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	FIP-Lugo-Mohave T/L(CA): Instal OPG	12,122,067
2	GMS Release 0.5 Implementation	11,046,667
3	MPR - Replace HB Valve	10,377,972
4	I:Lugo: Inst 500kV double breakers	10,316,183
5	LED2-17I-TDM-IPAlhambraCommunicatio	10,223,278
6	Pardee-Pastoria 220kV-North Cst-TLR	10,072,758
7	SD-TSFT Replacement-Test Smart Form	9,883,297
8	BISHOP SC - Facility Upgrade- CAP	9,877,794
9	2020/2021 Visability - Perimeter	9,808,948
10	GM - Long Term Planning Tool - R3.2	9,354,321
11	ACQ: Falcon Ridge, Rancho Cucamonga	9,192,119
12	FIP-CFF~5057-5001--Wildlife: Engine	9,134,095
13	Edwards: Rebuild 33kV rack	8,954,397
14	CRRdBlf#1: TLRR Remediate Discrepan	8,932,740
15	Eldorado-Lugo: CA-Install OPGW	8,826,027
16	31 STRM REDLANDS EL DORADO FIRE CEM	8,679,353
17	2020 C&C Capital SVN	8,580,163
18	Moorpark: Relocate lines at Ormond	8,407,975
19	FIP-San Bernardino Sub:Install 220k	8,293,380
20	4570-8206--ET-01738*DEVERS-CARODEAN	7,976,450
21	KAW-Kaweah Relicensing (FERC #298)	7,959,759
22	CS Re-platform Planning ADC HW	7,945,284
23	IOC Visibility Expansion - C&C	7,936,301
24	San Joaquin Vlly SC - Facility Upgr	7,788,100
25	RE CEMA CREEK FIRE 9/4/20	7,755,640
26	ACQ: West of Devers (WOD)_FERC	7,734,816
27	SPD-Enhanced Overhead Inspection (E	7,584,079
28	8116-5001--Circle City (formerly Ho	7,576,463
29	Lancaster Sub: Construct new switch	7,542,564
30	SD-Legal Sharepoint Upgrade	7,415,842
31	Control-Haiwee:Rbuild tower/2 Lines	7,214,472
32	Bridge Sub: Rpl No.1 & 2 Bank	7,205,214
33	CFF~Leatherneck Sub: Licensing Phas	7,179,599
34	Pardee: Equip Position 16E with (2)	7,163,241
35	CFF~Laguna Bell Substation: Replace	6,967,685
36	2016-2024 Seismic Assessmnt Prog -	6,909,281
37	Control-Coso Segment TLRR	6,897,364
38	VI- EOI LEE VINING-POOLE ET-76532	6,634,482
39	GM - Grid Connectivity Model - DSI	6,630,646
40	SPD-Enhanced Overhead Inspection (E	6,544,508
41	GM - GMS R.5 SAT H/W	6,361,645
42	GM Cyber - ICS Visibility SW/PS	6,349,579
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	GM - Common Substation Platform (CS	6,328,337
2	Culver - Upgrade to SA3. Replace re	6,314,639
3	FIP-Devers Sub: Install 220 kV CBs	6,279,996
4	ACQ: West of Devers (WOD)_CPUC	6,185,823
5	DSP	6,141,152
6	SC CM STORM: THOMAS FIRE #2 12/5/2	6,134,083
7	CS-Mira Loma Sub-CIP 014 Program	6,014,680
8	Midway-Vincent No1 500kV-TLRR	6,004,776
9	SPD-SS/BR HPCC Setup-ARRA	5,996,202
10	DH L.Harvey/C.Hotta CAP ONRAMP CABL	5,964,080
11	CFF~Carodean Sub: Modify 115kV Swit	5,912,282
12	SA/SERRANO SUB-FAILED BUSHINGS	5,871,983
13	FIP-I: Calcite:new 220kV Interconne	5,772,573
14	TTC-ALH U_Carpinteria-Ventura FO Ca	5,735,330
15	Cadillac 12 kV Circuit % Narrows Su	5,710,675
16	CS-Lugo Sub-CIP 014 Program	5,635,077
17	2019 C&C Interior Protection - FRSC	5,578,180
18	Ivyglen Sub: Preliminary engineeri	5,557,094
19	Santa Ana SC - ADA Upgrades - CAPIT	5,408,750
20	Yorktown 12 kV Circuit % Narrows Su	5,386,565
21	Kernville SC - Facility Upgrade - C	5,379,132
22	Colorado River Substation:	5,327,832
23	MidwayVincent2 TLRR Remediation Nr	5,203,115
24	CS-Pardee Sub-CIP 014 Program	5,074,734
25	Next Gen ERP - Enterprise Trans	5,072,029
26	Inyokern-Randsburg Segment TLRR	5,023,142
27	CS-Vincent Sub-CIP 014 Program	5,009,895
28	GM - System Modeling Tool R3.2 - Ma	4,992,879
29	2019 C&C Data VFI	4,961,997
30	HL-Dam 1&2 Replace Controls	4,919,995
31	Red Bluff: Instl 2nd 500/220kV tran	4,818,843
32	U_Vincent-Monrovia DO Fiber Refresh	4,799,095
33	Control-Silver Peak-Zack Segment TL	4,752,022
34	CFF~Lugo Substation: Install new an	4,675,539
35	FIP-Eldorado-Mohave T/L: Instal OPG	4,635,411
36	TRTP 1: FIP Antelope-Pardee 500kV:	4,615,140
37	CFF~Recovery Substation:	4,562,235
38	DSP	4,513,388
39	Vincent: Update existing station li	4,465,934
40	RULE 20A - UG INSTALL	4,428,517
41	RULE 20A - UG INSTALL	4,365,963
42	SD-Transformer Connectivity Model	4,288,614
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	GROUP B-TLRR_A-C-D C-S (WO B)	4,183,002
2	DsrtStrWhrlwnd220kV GenTie Install	4,181,240
3	Villa Park:Replace No.2A Bank 220/6	4,064,746
4	Soquel Sub: Add (1) 28 MVA Unit	4,016,224
5	SPD -Scope & Cost Management Tool (	3,994,425
6	SMOO SAS VIYA Upgrade	3,992,655
7	Clarifiers Life Extension T3	3,987,983
8	Lafayette: Replace (9) 12kV CBs	3,982,311
9	Redlands SC - Facility Upgrade- CAP	3,962,801
10	SMOO_Windows 2008 Upgrade - Phase 1	3,929,114
11	TTC-RI U_LUGO-MIRA LOMA #2 F/W CABL	3,887,013
12	ACQ/Valley South Subtrans Project	3,862,357
13	DEVERS SUB - New Mtc & Test Bldg -	3,832,570
14	Kramer-Coolwater Segment TLRR	3,810,430
15	SPD - CRAS Refresh	3,785,495
16	AFUDC for CPUC Portion of 800063633	3,767,765
17	Digital SMP Phase I U3	3,763,043
18	2019/2020 C&C TI Visibility - BA	3,748,348
19	TTC-RI STORM CREEK FIRE	3,711,422
20	GM - Cybersecurity - Master R3	3,702,180
21	Capacitor Cal 500/220(T): Replace a	3,701,999
22	BSH-Bishop Creek Relicensing	3,694,694
23	GROUP B-TLRR_A-DC-M-S-S (WO A)	3,665,098
24	Mira Loma-Replace 30 66kV CBs	3,635,860
25	GM Cyber - Interior CSOC SW/PS	3,631,456
26	(ENGINEERING) TLRR-V-A-P-PT014501	3,585,175
27	SPD-PII Encryption Phase II	3,582,252
28	2019 /2020 C&C ECS Phase II	3,509,336
29	CS-Eldorado Sub-CIP 014 Program	3,465,464
30	VI- EOI CASA DIABLO-CONTROL ET-009	3,451,895
31	Beverly 66/4.16 (D): Replace (30) 4	3,425,301
32	GM - DRP External Portal - R3.4 Mas	3,404,357
33	PSPS Automation and Customer Notifi	3,393,206
34	Red Bluff(RNU):Equip (1) 220kV T/L	3,332,947
35	NEW UG LINE PIN 800300	3,315,248
36	Inyo: Replace phase shifter & hybri	3,310,610
37	Kramer-Tortilla Segment TLRR	3,286,231
38	Eagle Mountain: Rplc 3A Bank 220/66	3,245,738
39	GM Cyber - Interior (PKI) SW/PS	3,243,747
40	Pardee-Seismic-instl brace and spac	3,238,684
41	Pastoria-Seismic-instl brace and sp	3,225,905
42	FIP-Mesa-Rio Hondo2: Install 3000ft	3,216,405
43	TOTAL	5,026,944,132

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	GM Cyber - Vendor DMZ SW/PS	3,212,366
2	Mt. View Gen Station Refresh	3,187,160
3	Serrano: Install conduit and AC fee	3,173,232
4	Valley Sub: Equip a new 115 kV posi	3,137,885
5	VI- EOI CASA DIABLO-CONTROL-SHERWI	3,136,492
6	Sunny Dunes 33/4 (D): Replace 1/2 B	3,117,546
7	Rector: Replce existing emerg. gene	3,088,543
8	DPT_Aerial and Transmission Inspect	3,049,077
9	Laguna Bell:Replce (61) 66kV discon	3,041,283
10	Vista-Install LBFB,MEER,SL&P, Gen	3,030,224
11	Barre Sub: Siesmic Mitigation Proje	3,029,624
12	Johanna:Install double breakers on	2,983,247
13	Laguna Bell: Replace 14 existing 66	2,979,368
14	51-CLAIM DETERIORATED PGE POLES HIG	2,944,816
15	SPD-Energy Data in the Cloud (Snowf	2,921,220
16	Gateway 6030 - EOC Expansion	2,886,815
17	SA-48-ACCESSROAD CH CAMP PENDELTON,	2,873,610
18	Main Generator Stator Rewind U1	2,871,109
19	SC-CM: Moorpark-Santa Clara No.1: T	2,863,127
20	Ezy Data Platform	2,831,412
21	Capacitor Az 12/500 (G):Replace and	2,821,044
22	FIP-Eldorado-Lugo T/L(CA): Clear in	2,813,479
23	GMS Release 2.0 Design	2,790,347
24	Hinson Sub: Seismic Mitigation Proj	2,776,801
25	DSP	2,769,551
26	CAP ON RAMP RELOCATON EXISTING	2,768,100
27	DSP	2,767,322
28	Gorman-Kern River 1 Segment TLRR	2,764,078
29	GM - GMS Release 1.0 FAT H/W	2,749,607
30	La Cienega: Replace No.3 Bank 220/6	2,744,586
31	Santa Ana Bldg A - Seismic Upgrades	2,733,406
32	SPD - Scope Mapping Tool Phase-3 &	2,690,131
33	SPD-EPM Business Process Automation	2,683,944
34	SPD- Enterprise Content Mgmt	2,648,065
35	RAJAGOM-19I-2020-Infra Refresh-ALH-	2,626,346
36	Baker: Install (1) new transformer	2,599,038
37	CSOD - Staff Aug Capital	2,589,287
38	SD-CSOD Staff Augmentation	2,585,567
39	Tesla Mobile Storage Battery Projec	2,563,146
40	Lugo-Mira Loma No.3 500kV Ph2-TLRR	2,556,223
41	SC JS STORM-RETAINING WALLS,GOLETA-	2,545,579
42	Kern River 1-Correction Segment TLR	2,509,261
43	TOTAL	5,026,944,132

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

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SPD-SS/BR HPCC Setup-ARRA-HW-ADC an	2,501,994
2	Phelan:ReplaceNo4bank with 2 28MVA	2,482,535
3	MPPH Replace LV Switchgear	2,476,422
4	CFF~Carnival Sub: Install new 66kV	2,473,293
5	LUEVAND-20I-NCE DA Radio Deployment	2,468,648
6	Correction-Cummings Segment TLRR	2,463,944
7	Colorado River: Install (1) line po	2,457,106
8	Pomona TSD - R/R Fire Protect Sys (	2,439,622
9	CFF~ColRvr(NU): 220kV Line/Bank Pos	2,432,182
10	El Nido: Upgrade Security Fence & L	2,428,426
11	Ellis Substation (RLA Facilities -	2,387,618
12	Baker-Dunn Siding Segment TLRR	2,362,376
13	Rio Hondo - Replace disconnect swit	2,348,182
14	CS-Irvine Operations Center-CIP 014	2,342,145
15	TLRR PRI A2 4502353 (168)	2,326,372
16	Bailey-Pardee:TLRR Remediation	2,315,693
17	DSP	2,313,237
18	LUEVAND-19I-FAN PLTE Eval-RosemeadG	2,311,430
19	PVCGP-Plant 2-Way Radio Replacement	2,290,618
20	GM - GMS E2E Testing Hardware	2,285,380
21	RI - DEVERS - REPR ABNORMAL OIL POW	2,283,514
22	Fogarty-Ivyglen (EPC) - Re-route ci	2,279,494
23	CS-SERRANO SUB - Perimeter Security	2,251,421
24	IOC - ASCO Switchgear Integration	2,241,860
25	License Renewal - Update Project	2,234,032
26	DSP DSPPIF #933311, NORDINA % COSTA	2,229,734
27	RULE 20A - UG INSTALL	2,221,017
28	Big Creek 3-Rector 1 TLRR Remediati	2,213,495
29	SPD-CCPA PHASE 2	2,206,993
30	San Dimas 66/12kV-Replace relays.	2,193,162
31	DH I5 WIDENING SEG 5 PROJECT ID 114	2,183,323
32	SPD-EOI-Notifications Automation(SB	2,181,792
33	TTC - RI U_BAYSIDE-GISLER FO (03199	2,178,039
34	Del Amo: Reconductor 66 kV bus sect	2,163,297
35	Neenach - REFCL Pilot Project	2,143,928
36	Pickle Meadows 16 kV Circuit Bridge	2,140,357
37	Alhambra CF - New Whse/Yard Re-Org	2,113,905
38	SD-CCA - Phase 4 - ODS for EDI 867	2,109,692
39	NGT1-19I-TDM2IP-EFDT-ADC-AlhambraDa	2,107,895
40	City of Costa Mesa GE LED Fixtures	2,085,947
41	CS Re-Platform Captial	2,076,433
42	Control-Deep Springs Segment TLRR	2,072,823
43	TOTAL	5,026,944,132

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	CAP ONRAMP RIVER XINGS	2,067,982
2	BUY AMERICA-OCTA CAL TRANS 405 WIDE	2,064,367
3	DH LH RELO OH CALTRANS - I-5 @ VALL	2,035,086
4	RI COND REPL 22.1 MIL COND REPLC HA	2,030,903
5	Fishlake Valley-Silver Peak Segment	2,012,553
6	Deep Springs-Fishlake Valley Segmnt	2,012,552
7	TLRR (11) 4510584 HIGHGROVE-PEPPER	2,009,563
8	FIP-Mesa-Rio Hondo1: Install 4 strc	1,988,886
9	PV1ER-Polar Cran Unit 1	1,981,770
10	RE Erosion Control CEMA Creek Fire	1,978,666
11	U_PARDEE-VINCENT NO.2 FW(06080)	1,909,951
12	Casa Diablo (DU): Install relays fo	1,906,837
13	LP Feedwater Heater 2C Repl Mod U2	1,898,777
14	Gateway 6070 - Suite C Remodel - CA	1,897,675
15	U_Devers-Vista OPGW 09076_CRF	1,891,945
16	SPD-EPM Analytics-UMA Replacement	1,880,736
17	SPD - ORLS-Outage Requests and Logg	1,870,638
18	RULE 20A - UG INSTALL RULE 20A - UG	1,861,528
19		1,854,801
20	DH CS CH CAP ON RAMP RECABLE PHASE	1,851,437
21	GM - GMS R.5 FAT H/W	1,840,282
22	SD-Remote Sensing-Aerial Surv Insp-	1,838,314
23	DSP	1,820,675
24	Viejo: Replace 66kV line relays	1,812,843
25	MOBILE HOME PARK CONVERSION	1,798,996
26	Charge Ready-Cust Side LA Co. I	1,798,229
27	Vista Sub: Seismic Mitigation Proje	1,764,197
28	CFF~Webmet: Construct new 66/12 kV	1,759,141
29	TTC-RI U_PISGAH-GALE F.O. CABLE (08	1,749,622
30	2020/2021 Capital WH	1,747,296
31	TLRR (31) 4510635 EL CASCO-PUREWATE	1,738,049
32	GRID RESILIENCY HOTLINE 555 3/12/20	1,729,592
33	33 RULE 20B - UG INSTALL RULE 20B -	1,729,417
34	Antelope Sub: Retrofit current 500k	1,716,897
35	Del Amo Seismic Mitigation	1,716,533
36	RI - EAGLE MOUNTAIN - RPL/RMV OPN/S	1,711,611
37	GRID RESILIENCY	1,711,376
38	SERC-GEN TIE.	1,709,979
39	43 STRM 2020-12-03T20:49:10Z	1,706,477
40	2019-2020 NERC - SX	1,705,814
41	GM - GMS Vendor DMZ	1,705,568
42	DSP	1,704,306
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Fremont 66/16 Replace banks	1,696,220
2	Deferred - KR3 Rebuild Sandbox	1,694,136
3	SD - GE Smallworld Technical Upgrad	1,688,944
4	El Nido: Add two CRAS mitigation re	1,685,613
5	DSP DSPSUBSTATION ELIMINATION-DOHEN	1,678,300
6	Long Beach SC - ADA Upgrades - CAPI	1,671,946
7	SMOO - HCI Migration - Phase 2	1,670,034
8	GRID RESILIENCY - 0555 HOTLINE 3/13	1,663,260
9	LP Feedwater Heater Repl U1R22	1,658,164
10	Eldorado-Sloan Canyon T/L:	1,657,861
11	GRID RESILIENCY	1,651,475
12	Edwards Sub: Rpl No1 Bank	1,645,691
13	PV1PM - ULT HEAT SINK-SPRAY POND FI	1,641,607
14	DSP	1,634,235
15	PREVENTIVE MAINT (ELECTIVE OPTION)	1,629,563
16	Deferred - BC8 - High pressure pipi	1,628,998
17	GM Cyber - ICS Security SW/PS	1,628,613
18	SPD-EPM Analytics-DS Decommissionin	1,615,898
19	City of Camarillo - LED Conversion	1,609,898
20	GRID RESILIENCY	1,603,678
21	SPD-CMP Rel 2.1 Capital	1,603,452
22	MOBILE HOME PARK CONVERSION	1,600,184
23	Big Creek 1-Big Creek 2 220kV-TLRR	1,598,621
24	DSP	1,597,160
25	47 LED LS-1 OPTION E STREETLIGHT CO	1,588,450
26	CO - Remove & Replace 5 spans of bu	1,582,075
27	GRID RESILIENCY HOTLINE 555 3/12/20	1,577,836
28	MPPH-Automation Upgrade	1,575,375
29	Moorpark Sub - Telecom Rm Expansion	1,572,542
30	Eric: Replace 12 12kV CBs+1 12kV SW	1,559,986
31	Distributables 2020	1,558,747
32	Ridgecrest Garage - Design/Program	1,554,465
33	Eagle Mtn Sub: Install relay&progra	1,551,066
34	DSP	1,550,565
35	Walnut: Replce existing emerg. Gene	1,547,561
36	Barstow:Rplce NO.1E & NO.1W BANK 33	1,540,639
37	EOI (Work Manageent Integration)	1,539,299
38	DSP	1,536,879
39	DSP	1,525,052
40	Rio Hondo Seismic Mitigation	1,521,912
41	CS - Devers Sub Perimeter Security	1,518,806
42	SC JS/LH STORM SAYRE FIRE CRIB WALL	1,507,368
43	TOTAL	5,026,944,132

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	Red Bluff Sub:Install line/relays/a	1,506,956
2	EOI POLE REPLACEMENT - 875376E, 144	1,504,286
3	Magunden-Springville 230 kV No.2: R	1,503,381
4	Cima-Eldorado #2 CA Segment TLRR	1,500,331
5	DSP	1,488,817
6	RELOCATE FACILITIES	1,484,095
7	CFF~Whirlwind Sub(IF): Install the	1,483,095
8	PLANT BETTERMENT/UPGRADING DISTRIBU	1,482,789
9	2020 SCE Employee Charging Program	1,477,824
10	Normal Chiller Replacement U2	1,474,975
11	Trask 66/12- Replace transformers	1,468,530
12	TTC-ALH U_FOC Refresh Eaglerock-Par	1,458,543
13	CFF-TARIFF-Whirlwind(IF):Instl pos	1,452,681
14	CFF~Barre (DU): Install dist facili	1,446,172
15	Barre: Install DFR	1,446,005
16	SPD-GAS-PEAKERS-CAPITAL	1,445,167
17	Magunden-Springville 230 kV No.1: R	1,435,389
18	Google Cloud Platform - R2	1,418,788
19	BSH-Rush Creek Relicensing (FERC #1	1,411,070
20	LIDAR Equipment	1,411,033
21	GRID RESILIENCY	1,408,925
22	T&D Consolidated Training Ctr - CAP	1,408,341
23	DA_T&D IRD - Inspection Application	1,405,014
24	SC JS/KH 4605-2126--ET-01821* ET-00	1,397,168
25	CS-Alhambra Data Center-CIP 014 Pro	1,396,225
26	GRID RESILIENCY	1,391,491
27	SMOO - Dynatrace Application Monito	1,384,747
28	Serrano-Valley 500kV-San Jac-TLRR	1,384,306
29	Rio Hondo Sub: Install new APP hard	1,382,304
30	34 STRM 2020-10-26T14:00:10Z	1,372,919
31	BSH-Intake 2 Spillway Modification	1,365,615
32	2019 C&C IXKS Perimeter - ADC	1,363,027
33	Trask Sub: Replace (1) 12kV Switche	1,359,784
34	2019 C&C IXKS Perimeter - IOC	1,359,065
35	Antlope-Big Sky:Instal 220kV Gen Ti	1,358,493
36	SHAVER LAKE S/C TLRR MATERIAL YARD	1,354,436
37	Felton: Equip pos #4 w 66kV CB	1,354,328
38	GRID RESILIENCY HOTLINE 555 10/22/1	1,350,006
39	Santa Clara: Replace (4) 220 KV Cir	1,339,813
40	SPD-IMEP 2020 Capital Cost Tracking	1,338,353
41	GM Cyber - GDC Program Support	1,335,590
42	SC CM STORM #2: WOOLSEY FIRE 11/8/2	1,335,273
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	2020/2021 C&C Firewall Enhancement	1,333,949
2	RELOCATE FACILITIES RELOCATE FACILI	1,331,925
3	SPD-Microsoft Teams Deployment - Ph	1,323,054
4	Beverly:Replce (6) Cap Banks and re	1,318,850
5	PLANT BETTERMENT/UPGRADING DISTRIBU	1,311,580
6	Lugo-Pisgah #2 Segment TLRR	1,305,950
7	RULE 20B - UG INSTALL RULE 20B - UG	1,305,490
8	ADDED FACILITIES ADDED FACILITIES	1,304,168
9	Villa Park - Replace (4) cap banks&	1,303,096
10	San Onofre Seismic Mitigation	1,298,357
11	GROUP C-NEW 66KV LINE FOR CUSTOMER	1,290,900
12	RI ET-00083 Lugo-Mira Loma #2	1,287,757
13	DSP	1,280,942
14	SD-CCC IVR Upgrade - Phase 2 - CS	1,278,699
15	DUONGT-19I-TDM2IP-EFDT-Vincent-Vinc	1,277,685
16	TTC-RI 8456-0697--KRAMER HOLGATE FO	1,276,645
17	Pisgah-Cima #2 Segment TLRR	1,273,501
18	Pardee-Pastoria-Warne 220kV-NrthCst	1,257,512
19	DSP	1,256,412
20	SMOO_IBM TDS LDAP Upgrade	1,255,162
21	VA-CONSTRUCT NEW 8 MI 115KV LINE FO	1,253,782
22	Moulton - Install (1) CB, replace (	1,248,330
23	Cima Sub: Install On-Line DGA Equip	1,245,867
24	Moraga: Replace (11) 12kV CBs	1,243,845
25	SD-Perimeter Sec CIP14: Phase 4 Lab	1,234,688
26	DH UG RULE 20C ESSEX PROPRTIES - VI	1,233,156
27	SOCA Defensive Strategy Upgrades	1,232,536
28	77 GRID RESILIENCY 177968 STARGLOW	1,228,573
29	R/R 1 DET POLES (822045E)	1,226,784
30	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,219,837
31	CRE - Data Center Seismic Retrofit	1,215,089
32	SMOO - Map3D Upgrade	1,214,368
33	VI- EOI LEE VINING-RUSH CREEK ET-	1,212,893
34	Center Sub: Seismic Mitigation Proj	1,212,413
35	SMOO SAP GRC Solution	1,209,263
36	CFF~Red Bluff(IF):DblBrkr line pos	1,204,538
37	Pechanga: Replace (7) 12kV CBs	1,200,956
38	Victor Sub: Seismic No. 3 Bank	1,199,633
39	Lugo: Replace 3 500kV CBs+6 500kV D	1,198,875
40	DUONGT-19<(>&<)>20I-Incident Manage	1,191,773
41	Goldhill: Replace (2) 33kV Switcher	1,190,654
42	VI- EOI CASA DIABLO-RUSH CREEEK E	1,175,321
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	C&C Perimeter Firewall Migration	1,172,532
2	CAP ONRAMP COND REPLACE 4360'	1,171,752
3	GRID RESILIENCY	1,166,597
4	RELOCATE FACILITIES - NON BILLING R	1,165,427
5	47 STRM 2020-09-05T19:58:30Z	1,165,325
6	PROGRAM PREVENTIVE MAINTENANCE(CABL	1,165,177
7	FIP-Mesa-Mira Loma: Install 2 strct	1,163,394
8	Big Creek 3 BCT Upgrades+Relays	1,163,260
9	GCC Alhambra: Install 5 servers	1,161,461
10	Rancho Vista Sub: DGA&monitor 3&4AA	1,161,107
11	Rector: Install PMU	1,160,448
12	Lennox 16/4kV-Replace CB's	1,160,142
13	GRID RESILIENCY	1,152,231
14	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,149,480
15	GRID RESILIENCY	1,148,108
16	Cima-Eldorado #1 CA Segment TLRR	1,147,267
17	Kramer: Upgrade Line Relay	1,145,798
18	IR COND RPLC 2.34 MIL COND RPLC BLI	1,141,700
19	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,141,363
20	RPL/RMV ENVR HZRD OIL XFMR	1,141,348
21	.Fair Oaks:Upgrade HMI/PLC to SA3 H	1,134,993
22	SD-IGAM - Security & Controls	1,133,118
23	LED2-19I-TDM-IP: EarlyFieldDeployme	1,132,216
24	Colorado River: Instal fac. Switchr	1,129,454
25	Santa Clara Seismic Mitigation	1,129,032
26	SPD-Operator Rounds and Narrative L	1,128,959
27	PLANT BETTERMENT/UPGRADING DISTRIBU	1,126,985
28	CT Life Extension 2020 U1	1,123,511
29	Lugo-Mira Loma No2 500kV-TLRR	1,123,223
30	Control 115 kV CBs+MEER for ATRA	1,121,704
31	Mira Loma:Replace NW IR8600 RTU(2)	1,110,602
32	Big Creek 3-Rector No. 2 220kV-TLRR	1,110,546
33	NetComm Encryption	1,107,540
34	San Marino Replace (5) 4kV CBs	1,104,031
35	LINE EXTENSION	1,103,927
36	GRID RESILIENCY	1,103,756
37	RULE 20A - UG INSTALL RULE 20A - UG	1,097,727
38	WADHWASM-17I-MWR: Bail-Lugo-RanchoV	1,094,747
39	GRID RESILIENCY	1,093,559
40	Repetto: Upgrade HMI/PLC to SA3 Hyb	1,092,517
41	SMOO iVOS Upgrade	1,086,856
42	GRID RESILIENCY	1,086,005
43	TOTAL	5,026,944,132

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	04/14/2021	End of 2020/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	Moorpark-Pardee No. 1: Relocate to	1,078,999
2	MOBILE HOME PARK CONVERSION	1,078,727
3	Industry Sub: Rebuild 12kV switchge	1,077,954
4	EOI POLE REPLACEMENT - 949279E	1,074,744
5	San Bernardino Sub: Seismic Mit Prj	1,070,938
6	MV Relay Replacements Phase II	1,068,804
7	INFRASTRUCTURE REPLACEMENT 0555 HOT	1,066,599
8	PREVENTIVE MAINT (ELECTIVE OPTION)	1,066,586
9	Mira Loma Peaker Plant- Add Sewer -	1,065,165
10	OCI	1,062,654
11	RULE 20C - UG INSTALL RULE 20C - UG	1,062,440
12	Vestal Sub: Install new APP DFR(s)	1,061,018
13	CARRY OVER - SMOO_REDHAT AIX SUSE O	1,058,431
14	DH-A FLOREZ/A TRUEMAN DEL AMO-HINSO	1,058,070
15	GRID RESILIENCY	1,052,942
16	SD-PII Encryption	1,048,191
17	Pisgah-Cima #1 Segment TLRR	1,047,792
18	DPT_C3 - Supervisor View	1,047,022
19	DSP DSPDOHENY SUB IR FRINGE 4KV-UTI	1,045,536
20	PLANT BETTERMENT/UPGRADING DISTRIBU	1,044,916
21	Pastoria BCT Upgrades+Relays	1,041,148
22	GRID RESILIENCY	1,038,372
23	GROUP C-MPO TSP A-BANK PIN 7767 JOH	1,035,041
24	DSP DSPNEW CIRCUIT MELROSE 16KV OUT	1,034,803
25	El Nido Substation: On-Line DGA Equ	1,034,790
26	RattleSnake-Whirlwind(IF):Instll Ge	1,031,201
27	INSTALL SWITCH TO SUPPORT TOCI/LV S	1,024,472
28	DPT_AI/ML Image Analytics (Aerial)	1,021,232
29	GRID RESILIENCY	1,018,501
30	Irvine 66/12 - Upgrade 66kV Switchr	1,013,806
31	GM Cyber - Endpoint Security	1,013,264
32	FL- Florence Recreation Compl	1,012,355
33	TSD EV Chargers & Infrast Program -	1,010,811
34	PLANT BETTERMENT/UPGRADING DISTRIBU	1,010,646
35	SD-CCC IVR Upgrade - Phase 2 - IT	1,008,266
36	KAW1 Flume Rebuild/Hillside Stabili	1,007,225
37	DH-A FLOREZ/A TRUEMAN Del Amo-Lagun	1,006,856
38	77-GRID RESILIENCY2020 PIF 077669-	1,002,703
39	WORK ORDERS UNDER $1,000,000	1,383,837,468
40		
41		
42		
43	TOTAL	5,026,944,132

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	13,591,495,305	13,591,495,305		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,786,243,338	1,786,243,338		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,358,506	2,358,506		
7	Other Clearing Accounts	8,913,524	8,913,524		
8	Other Accounts (Specify, details in footnote):	4,344,177	4,344,177		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,801,859,545	1,801,859,545		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	550,021,246	550,021,246		
13	Cost of Removal	1,000,574,828	1,000,574,828		
14	Salvage (Credit)	176,954,127	176,954,127		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	1,373,641,947	1,373,641,947		
16	Other Debit or Cr. Items (Describe, details in footnote):	58,339,200	58,339,200		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	14,078,052,103	14,078,052,103		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	189,706	189,706		
21	Nuclear Production	1,648,871,946	1,648,871,946		
22	Hydraulic Production-Conventional	578,367,853	578,367,853		
23	Hydraulic Production-Pumped Storage				
24	Other Production	740,406,975	740,406,975		
25	Transmission	2,935,032,762	2,935,032,762		
26	Distribution	6,924,118,581	6,924,118,581		
27	Regional Transmission and Market Operation				
28	General	1,251,064,280	1,251,064,280		
29	TOTAL (Enter Total of lines 20 thru 28)	14,078,052,103	14,078,052,103		

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

Amortization of Regulatory Asset for Palo Verde Sunk Cost.

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	04/14/2021	End of 2020/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	Mono Power Company			
2	Capital Stock	03/02/70	none	100
3	Additional Paid-in Capital	03/02/70	none	2,749,150
4	Undistributed Earnings			-2,674,036
5				
6	Southern States Realty			
7	Capital Stock	01/22/73	none	100
8	Additional Paid-in Capital	01/22/73	none	
9	Undistributed Earnings			68,867
10				
11	Rounding			
12				
13				
14				
15				
16				
17				
18				
19				
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41				
42	Total Cost of Account 123.1 $ 143,655		TOTAL	144,181

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
		100		2
		2,749,150		3
-526		-2,674,562		4
				5
				6
		100		7
				8
		68,867		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
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				36
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				41
-526		143,655		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	04/14/2021	End of 2020/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	2,007,652	1,951,472	ELECTRIC
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	327,283,136	361,680,986	ELECTRIC
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	17,371,360	19,485,028	ELECTRIC
8	Transmission Plant (Estimated)	2,469,321	2,773,724	ELECTRIC
9	Distribution Plant (Estimated)	13,493,728	17,580,770	ELECTRIC
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,251,049	1,414,553	ELECTRIC
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	361,868,594	402,935,061	
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)	363,876,246	404,886,533	

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	04/14/2021	End of 2020/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)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year	565,148.00		53,288.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Allowances Used	8.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	565,140.00		53,288.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

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.

2022		2023		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
53,288.00		53,288.00		1,385,488.00		2,110,500.00		1
								2
								3
				53,288.00		53,288.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
						8.00		20
								21
								22
								23
								24
								25
								26
								27
								28
53,288.00		53,288.00		1,438,776.00		2,163,780.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
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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	04/14/2021	End of 2020/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)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year	482,987.00	1,532,677	289,632.00	509,522
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	NOx				
10	Fathom California	15,000.00	94,537		
11					
12					
13					
14					
15	Total	15,000.00	94,537		
16					
17	Relinquished During Year:				
18	Charges to Account 509	139,022.00	477,032		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Excess V2020 to FMV		-694,548		
23	Fathom California	50,000.00	94,537		
24	Expired NOx	142,989.00	902,531		
25	True Up	366.00	869		
26					
27					
28	Total	193,355.00	303,389		
29	Balance-End of Year	165,610.00	846,793	289,632.00	509,522
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
289,632.00	484,810	289,632.00	461,335	1,350,230.00	1,983,982	2,702,113.00	4,972,326	1
								2
								3
								4
								5
								6
								7
								8
								9
						15,000.00	94,537	10
								11
								12
								13
								14
						15,000.00	94,537	15
								16
								17
						139,022.00	477,032	18
								19
								20
								21
							-694,548	22
						50,000.00	94,537	23
						142,989.00	902,531	24
						366.00	869	25
								26
								27
						193,355.00	303,389	28
289,632.00	484,810	289,632.00	461,335	1,350,230.00	1,983,982	2,384,736.00	4,286,442	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
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								44
								45
								46

Schedule Page: 229 Line No.: 1 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line on page 110. Difference is due to $1,872,788 in GHG Allowances.

Schedule Page: 229 Line No.: 29 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line on page 110. Difference is due to $15,857,649 in GHG Allowances.

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	04/14/2021	End of 2020/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						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	Palo Verde Nuclear Generating	496,557		407	-18,797	477,760
22	Station over the authorized					
23	License Term January 1989 to					
24	July 2046					
25						
26						
27	Mohave Generating Station Plant	154,188		407		154,188
28	over the authorized License Term					
29	January 2006 to June 2016					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	650,745			-18,797	631,948

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	04/14/2021	End of 2020/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	128,775	143	(100,000)	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	3,974,539	143	(4,005,814)	143
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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

Project Type	Project Description	Costs Incurred	Account Charged	Reimbursements	Account Charged
Transmission	800250922 Interconnection Study	$ 67,995.14	143	$ -	143
Transmission	902694424 Interconnection Study	467.63	143	-	143
Transmission	902768270 Interconnection Study	5,582.00	143	-	143
Transmission	902994691 Interconnection Study	-	143	-	143
Transmission	902994692 Interconnection Study	-	143	-	143
Transmission	902994693 Interconnection Study	-	143	-	143
Transmission	903110326 Interconnection Study	54,730.18	143	(100,000.00)	143
	Total Transmission	**$ 128,774.95**		**$ (100,000.00)**	

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

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

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

Column (d) includes refunds that were paid to the Interconnection customer in 2020 resulting from payment 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	Project Description	Costs Incurred	Account Charged	Reimbursements	Account Charged
Generation	901854257 Interconnection Study	$ 1,274.06	143	$ -	143
Generation	902132736 Interconnection Study	18.45	143	-	143
Generation	902133733 Interconnection Study	4,811.47	143	26,002.14	143
Generation	902307066 Interconnection Study	1,207.06	143	-	143
Generation	902343311 Interconnection Study	4,041.54	143	31,067.28	143
Generation	902369760 Interconnection Study	(18.56)	143	8,703.93	143
Generation	902377012 Interconnection Study	18.45	143	-	143
Generation	902377371 Interconnection Study	4,908.99	143	214,888.31	143
Generation	902377647 Interconnection Study	4,112.12	143	46,661.03	143
Generation	902381580 Interconnection Study	4,459.51	143	105,981.04	143
Generation	902381581 Interconnection Study	18.45	143	-	143
Generation	902388981 Interconnection Study	4,678.69	143	23,568.62	143
Generation	902392017 Interconnection Study	18.45	143	-	143
Generation	902392469 Interconnection Study	983.05	143	-	143
Generation	902392471 Interconnection Study	3,913.89	143	34,172.69	143
Generation	902392481 Interconnection Study	-	143	1,180.28	143
Generation	902392482 Interconnection Study	-	143	711.46	143
Generation	902411236 Interconnection Study	5,619.46	143	(43,665.50)	143
Generation	902411237 Interconnection Study	1,274.06	143	-	143
Generation	902411245 Interconnection Study	1,274.06	143	-	143
Generation	902411247 Interconnection Study	1,274.06	143	-	143
Generation	902411259 Interconnection Study	1,274.06	143	-	143
Generation	902411271 Interconnection Study	85.37	143	-	143
Generation	902411275 Interconnection Study	1,274.06	143	-	143
Generation	902411364 Interconnection Study	5,986.40	143	-	143
Generation	902411932 Interconnection Study	32.19	143	8,820.90	143
Generation	902422029 Interconnection Study	2,945.34	143	-	143
Generation	902425160 Interconnection Study	10,176.32	143	-	143
Generation	902444603 Interconnection Study	459.15	143	-	143
Generation	902498289 Interconnection Study	4,774.51	143	76,866.21	143
Generation	902559735 Interconnection Study	481.60	143	-	143
Generation	902571526 Interconnection Study	4,158.69	143	-	143
Generation	902606945 Interconnection Study	502.76	143	(481.58)	143
Generation	902609409 Interconnection Study	(54,804.08)	143	(84,087.96)	143
Generation	902628304 Interconnection Study	2,530.36	143	4,258.28	143

Generation	902641336 Interconnection Study	2,504.37	143	5,762.14	143
Generation	902643016 Interconnection Study	328.27	143	-	143
Generation	902643952 Interconnection Study	2,247.35	143	(10,332.06)	143
Generation	902643953 Interconnection Study	4,768.90	143	(24,084.22)	143
Generation	902644072 Interconnection Study	4,637.75	143	(24,146.20)	143
Generation	902644074 Interconnection Study	8,399.55	143	(31,165.38)	143
Generation	902644075 Interconnection Study	6,459.50	143	(25,706.96)	143
Generation	902644078 Interconnection Study	5,837.20	143	(24,039.37)	143
Generation	902644121 Interconnection Study	5,351.52	143	(24,937.55)	143
Generation	902644122 Interconnection Study	4,570.27	143	(22,749.22)	143
Generation	902644123 Interconnection Study	7,569.92	143	-	143
Generation	902644124 Interconnection Study	12,382.18	143	(33,720.54)	143
Generation	902644127 Interconnection Study	8,241.57	143	-	143
Generation	902644129 Interconnection Study	7,725.30	143	-	143
Generation	902644132 Interconnection Study	7,786.40	143	-	143
Generation	902644134 Interconnection Study	7,993.16	143	-	143
Generation	902644138 Interconnection Study	7,514.35	143	-	143
Generation	902644139 Interconnection Study	4,680.22	143	(22,108.38)	143
Generation	902644143 Interconnection Study	1,923.42	143	-	143
Generation	902644145 Interconnection Study	14,429.41	143	-	143
Generation	902644150 Interconnection Study	11,535.79	143	-	143
Generation	902644152 Interconnection Study	12,052.73	143	(33,621.82)	143
Generation	902644153 Interconnection Study	7,500.42	143	-	143
Generation	902644155 Interconnection Study	11,111.19	143	(31,649.98)	143
Generation	902644160 Interconnection Study	6,549.00	143	(22,952.48)	143
Generation	902644165 Interconnection Study	8,104.33	143	-	143
Generation	902644167 Interconnection Study	8,111.19	143	-	143
Generation	902644168 Interconnection Study	7,600.16	143	-	143
Generation	902644169 Interconnection Study	7,564.93	143	-	143
Generation	902644172 Interconnection Study	7,974.42	143	-	143
Generation	902644181 Interconnection Study	(53.54)	143	(3,604.65)	143
Generation	902644184 Interconnection Study	7,573.26	143	-	143
Generation	902644186 Interconnection Study	(16,505.11)	143	(528.81)	143
Generation	902659036 Interconnection Study	71.28	143	(1,602.96)	143
Generation	902694331 Interconnection Study	12,783.88	143	-	143
Generation	902694332 Interconnection Study	13,500.74	143	-	143
Generation	902697995 Interconnection Study	4,253.73	143	-	143
Generation	902699185 Interconnection Study	98.90	143	-	143
Generation	902699364 Interconnection Study	248.26	143	202,562.03	143
Generation	902699365 Interconnection Study	17,283.23	143	-	143
Generation	902699564 Interconnection Study	129.85	143	-	143
Generation	902699567 Interconnection Study	9,805.63	143	-	143
Generation	902699937 Interconnection Study	32,340.13	143	-	143
Generation	902700102 Interconnection Study	12,136.31	143	-	143
Generation	902700104 Interconnection Study	16,810.14	143	23,197.74	143
Generation	902700362 Interconnection Study	17.20	143	(380.74)	143
Generation	902700363 Interconnection Study	17.20	143	(380.74)	143
Generation	902704746 Interconnection Study	172.37	143	-	143
Generation	902705004 Interconnection Study	(3,238.17)	143	-	143
Generation	902705009 Interconnection Study	9,805.63	143	-	143
Generation	902705071 Interconnection Study	15,896.90	143	68,446.89	143
Generation	902710089 Interconnection Study	12,922.44	143	-	143
Generation	902715041 Interconnection Study	16,367.70	143	68,903.83	143
Generation	902716587 Interconnection Study	9,575.89	143	-	143
Generation	902716589 Interconnection Study	12,023.55	143	-	143
Generation	902720288 Interconnection Study	11,317.05	143	-	143
Generation	902720713 Interconnection Study	13,181.77	143	-	143
Generation	902721212 Interconnection Study	11,136.46	143	-	143

Generation	902721214 Interconnection Study	6,148.14	143	-	143
Generation	902721215 Interconnection Study	6,430.57	143	-	143
Generation	902721849 Interconnection Study	12,368.19	143	-	143
Generation	902724702 Interconnection Study	12,024.01	143	-	143
Generation	902724703 Interconnection Study	13,467.74	143	-	143
Generation	902724705 Interconnection Study	16,332.96	143	121,041.07	143
Generation	902724706 Interconnection Study	120.30	143	152,623.28	143
Generation	902725423 Interconnection Study	13,444.59	143	-	143
Generation	902725431 Interconnection Study	13,751.34	143	-	143
Generation	902725704 Interconnection Study	6,354.17	143	-	143
Generation	902726861 Interconnection Study	105.26	143	(3,407.93)	143
Generation	902729231 Interconnection Study	111.61	143	(3,166.84)	143
Generation	902757025 Interconnection Study	3,298.24	143	-	143
Generation	902767593 Interconnection Study	2,140.33	143	-	143
Generation	902767658 Interconnection Study	2,824.06	143	(6,975.83)	143
Generation	902768268 Interconnection Study	2,905.08	143	(7,708.91)	143
Generation	902768269 Interconnection Study	3,454.71	143	-	143
Generation	902768952 Interconnection Study	1,248.50	143	(3,521.70)	143
Generation	902768955 Interconnection Study	344.80	143	-	143
Generation	902777175 Interconnection Study	9,608.55	143	(22,302.08)	143
Generation	902777176 Interconnection Study	9,796.41	143	(23,028.38)	143
Generation	902777177 Interconnection Study	8,369.31	143	(20,932.34)	143
Generation	902777178 Interconnection Study	9,544.04	143	(22,139.86)	143
Generation	902777212 Interconnection Study	7,583.60	143	(20,263.40)	143
Generation	902777213 Interconnection Study	8,441.94	143	(20,995.72)	143
Generation	902777214 Interconnection Study	(992.13)	143	-	143
Generation	902777215 Interconnection Study	8,322.77	143	(20,881.93)	143
Generation	902777216 Interconnection Study	9,093.24	143	(21,621.15)	143
Generation	902777217 Interconnection Study	6,574.88	143	(14,371.83)	143
Generation	902777256 Interconnection Study	8,119.71	143	(20,792.31)	143
Generation	902777257 Interconnection Study	9,279.63	143	(21,893.08)	143
Generation	902777310 Interconnection Study	9,701.74	143	(22,278.22)	143
Generation	902777311 Interconnection Study	7,880.22	143	(20,463.66)	143
Generation	902777312 Interconnection Study	10,694.00	143	(23,529.88)	143
Generation	902777313 Interconnection Study	9,427.90	143	-	143
Generation	902777314 Interconnection Study	7,372.40	143	(20,068.16)	143
Generation	902777315 Interconnection Study	8,695.06	143	(21,340.47)	143
Generation	902777317 Interconnection Study	7,991.09	143	(20,662.62)	143
Generation	902777318 Interconnection Study	8,750.71	143	(22,049.54)	143
Generation	902777419 Interconnection Study	8,317.99	143	(20,969.08)	143
Generation	902777420 Interconnection Study	8,274.18	143	(20,933.15)	143
Generation	902777421 Interconnection Study	8,585.22	143	(21,224.89)	143
Generation	902777422 Interconnection Study	8,282.28	143	(20,936.08)	143
Generation	902777423 Interconnection Study	7,068.66	143	(14,837.45)	143
Generation	902777425 Interconnection Study	8,889.38	143	(21,255.51)	143
Generation	902777426 Interconnection Study	9,403.48	143	(22,020.20)	143
Generation	902777428 Interconnection Study	9,447.05	143	(22,045.79)	143
Generation	902777430 Interconnection Study	10,087.57	143	(22,655.36)	143
Generation	902777431 Interconnection Study	10,591.54	143	(23,137.04)	143
Generation	902777432 Interconnection Study	8,043.57	143	(20,613.67)	143
Generation	902777433 Interconnection Study	8,870.89	143	(21,498.56)	143
Generation	902777440 Interconnection Study	9,963.74	143	(27,191.37)	143
Generation	902777442 Interconnection Study	8,356.34	143	(21,027.11)	143
Generation	902777443 Interconnection Study	8,081.74	143	(15,747.88)	143
Generation	902777444 Interconnection Study	8,328.36	143	(20,971.45)	143
Generation	902777445 Interconnection Study	8,819.04	143	(21,451.10)	143
Generation	902777446 Interconnection Study	8,794.81	143	(21,338.52)	143
Generation	902777447 Interconnection Study	8,702.43	143	(21,256.51)	143

Generation	902777459 Interconnection Study	(849.90)	143	(11,794.90)	143
Generation	902777460 Interconnection Study	6,188.05	143	(14,005.33)	143
Generation	902777463 Interconnection Study	9,083.19	143	(21,616.51)	143
Generation	902777464 Interconnection Study	6,684.70	143	(14,482.30)	143
Generation	902779170 Interconnection Study	197.86	143	(1,786.31)	143
Generation	902781037 Interconnection Study	2,198.68	143	-	143
Generation	902781038 Interconnection Study	1,941.43	143	(7,796.27)	143
Generation	902781299 Interconnection Study	31,615.60	143	-	143
Generation	902831421 Interconnection Study	6,696.06	143	-	143
Generation	902836481 Interconnection Study	77.11	143	(2,206.23)	143
Generation	902844648 Interconnection Study	243.17	143	-	143
Generation	902844650 Interconnection Study	-	143	-	143
Generation	902845048 Interconnection Study	6,276.36	143	-	143
Generation	902847968 Interconnection Study	7,798.58	143	-	143
Generation	902852322 Interconnection Study	(514.37)	143	-	143
Generation	902852323 Interconnection Study	52.31	143	(1,537.04)	143
Generation	902853193 Interconnection Study	214.92	143	-	143
Generation	902853194 Interconnection Study	1,579.20	143	-	143
Generation	902853292 Interconnection Study	970.50	143	-	143
Generation	902853294 Interconnection Study	485.50	143	-	143
Generation	902853297 Interconnection Study	56.89	143	-	143
Generation	902854783 Interconnection Study	7,350.34	143	-	143
Generation	902854784 Interconnection Study	3,750.24	143	(10,000.00)	143
Generation	902856346 Interconnection Study	285.62	143	145,377.23	143
Generation	902857252 Interconnection Study	2,049.65	143	-	143
Generation	902862084 Interconnection Study	798.77	143	98,232.49	143
Generation	902862086 Interconnection Study	41,054.52	143	-	143
Generation	902864434 Interconnection Study	1,294.39	143	17,686.71	143
Generation	902868530 Interconnection Study	3,466.82	143	(4,972.68)	143
Generation	902872221 Interconnection Study	7,947.75	143	52,759.58	143
Generation	902872428 Interconnection Study	1,358.76	143	129,753.79	143
Generation	902873795 Interconnection Study	(147.34)	143	-	143
Generation	902877357 Interconnection Study	782.79	143	-	143
Generation	902877536 Interconnection Study	344.52	143	(1,098.29)	143
Generation	902880737 Interconnection Study	9,428.97	143	-	143
Generation	902903177 Interconnection Study	7,563.56	143	-	143
Generation	902903178 Interconnection Study	1,891.38	143	-	143
Generation	902903619 Interconnection Study	3,209.28	143	-	143
Generation	902903620 Interconnection Study	3,610.68	143	-	143
Generation	902903621 Interconnection Study	-	143	-	143
Generation	902908304 Interconnection Study	9,676.40	143	-	143
Generation	902922268 Interconnection Study	6,063.79	143	-	143
Generation	902922686 Interconnection Study	5,271.21	143	-	143
Generation	902924545 Interconnection Study	5,939.77	143	(5,680.77)	143
Generation	902924546 Interconnection Study	15,999.38	143	(15,358.80)	143
Generation	902924547 Interconnection Study	7,537.30	143	(7,218.59)	143
Generation	902924548 Interconnection Study	9,973.31	143	(9,560.99)	143
Generation	902924549 Interconnection Study	7,210.82	143	(6,902.53)	143
Generation	902924550 Interconnection Study	4,884.38	143	(4,671.34)	143
Generation	902924698 Interconnection Study	(587.33)	143	(3,459.55)	143
Generation	902925260 Interconnection Study	7,952.44	143	-	143
Generation	902925269 Interconnection Study	3,834.27	143	(4,502.40)	143
Generation	902928205 Interconnection Study	11,068.22	143	(10,570.03)	143
Generation	902928206 Interconnection Study	6,075.63	143	(5,817.02)	143
Generation	902928207 Interconnection Study	4,645.81	143	-	143
Generation	902928208 Interconnection Study	7,985.40	143	(7,650.97)	143
Generation	902928209 Interconnection Study	5,704.14	143	(5,772.67)	143
Generation	902928210 Interconnection Study	3,437.50	143	(3,830.04)	143

Generation	902928211 Interconnection Study	5,544.61	143	(6,063.40)	143
Generation	902928212 Interconnection Study	5,465.28	143	(5,234.03)	143
Generation	902928214 Interconnection Study	6,965.22	143	(6,766.12)	143
Generation	902928215 Interconnection Study	1,156.70	143	(1,106.43)	143
Generation	902928216 Interconnection Study	3,994.97	143	-	143
Generation	902928217 Interconnection Study	3,706.81	143	(4,342.68)	143
Generation	902928218 Interconnection Study	2,902.47	143	(3,560.41)	143
Generation	902928339 Interconnection Study	3,460.83	143	(3,984.68)	143
Generation	902928340 Interconnection Study	3,044.22	143	(2,975.78)	143
Generation	902928341 Interconnection Study	3,745.70	143	(3,741.50)	143
Generation	902928342 Interconnection Study	3,716.95	143	(4,501.74)	143
Generation	902928343 Interconnection Study	3,731.04	143	(4,262.26)	143
Generation	902928344 Interconnection Study	2,242.69	143	(2,686.96)	143
Generation	902928345 Interconnection Study	4,033.51	143	(4,094.24)	143
Generation	902928346 Interconnection Study	4,270.30	143	(4,095.31)	143
Generation	902928347 Interconnection Study	5,161.50	143	(5,229.37)	143
Generation	902928348 Interconnection Study	5,445.68	143	(5,297.01)	143
Generation	902928349 Interconnection Study	1,404.07	143	(1,685.77)	143
Generation	902928350 Interconnection Study	5,987.09	143	(6,067.42)	143
Generation	902928351 Interconnection Study	2,084.20	143	-	143
Generation	902928352 Interconnection Study	4,214.45	143	-	143
Generation	902928353 Interconnection Study	1,818.91	143	(2,562.52)	143
Generation	902928886 Interconnection Study	4,260.85	143	(4,734.95)	143
Generation	902929217 Interconnection Study	2,512.48	143	(2,536.64)	143
Generation	902937043 Interconnection Study	10,753.92	143	(56,000.00)	143
Generation	902937434 Interconnection Study	2,774.48	143	(2,500.00)	143
Generation	902937437 Interconnection Study	3,410.54	143	(3,266.32)	143
Generation	902941228 Interconnection Study	2,813.92	143	(3,235.31)	143
Generation	902942096 Interconnection Study	1,350.61	143	(1,289.10)	143
Generation	902951229 Interconnection Study	1,700.81	143	(1,627.26)	143
Generation	902957553 Interconnection Study	17,050.93	143	(60,000.00)	143
Generation	902965402 Interconnection Study	3,635.74	143	(3,478.67)	143
Generation	902965404 Interconnection Study	1,051.23	143	-	143
Generation	902966129 Interconnection Study	6,131.47	143	(5,840.73)	143
Generation	902966133 Interconnection Study	4,712.55	143	-	143
Generation	902970121 Interconnection Study	538.82	143	(521.83)	143
Generation	902970127 Interconnection Study	538.82	143	(521.83)	143
Generation	902981597 Interconnection Study	3,413.59	143	-	143
Generation	902994694 Interconnection Study	5,281.08	143	(5,021.36)	143
Generation	903000942 Interconnection Study	-	143	(10,000.00)	143
Generation	903020836 Interconnection Study	540.36	143	(10,000.00)	143
Generation	903040059 Interconnection Study	843.32	143	(808.18)	143
Generation	903041413 Interconnection Study	420.03	143	(399.42)	143
Generation	903041889 Interconnection Study	18,560.83	143	(250,000.00)	143
Generation	903041890 Interconnection Study	-	143	(10,000.00)	143
Generation	903041896 Interconnection Study	2,100.15	143	(1,997.08)	143
Generation	903044164 Interconnection Study	2,587.58	143	(10,000.00)	143
Generation	903044529 Interconnection Study	891.75	143	(860.93)	143
Generation	903055585 Interconnection Study	3,606.94	143	(3,477.83)	143
Generation	903056949 Interconnection Study	24,372.23	143	(120,000.00)	143
Generation	903059936 Interconnection Study	5,321.55	143	(10,000.00)	143
Generation	903059937 Interconnection Study	7,474.86	143	(7,220.25)	143
Generation	903059938 Interconnection Study	4,531.66	143	(4,422.72)	143
Generation	903060201 Interconnection Study	3,419.52	143	(3,294.29)	143
Generation	903062294 Interconnection Study	129.59	143	(10,000.00)	143
Generation	903062295 Interconnection Study	129.59	143	(10,000.00)	143
Generation	903076012 Interconnection Study	9,689.71	143	(9,310.67)	143
Generation	903076016 Interconnection Study	23,417.75	143	(100,000.00)	143

Generation	903076985 Interconnection Study	24,488.16	143	-	143
Generation	903076986 Interconnection Study	25,503.27	143	-	143
Generation	903076987 Interconnection Study	27,992.02	143	-	143
Generation	903076989 Interconnection Study	24,254.97	143	-	143
Generation	903077021 Interconnection Study	23,467.67	143	-	143
Generation	903077023 Interconnection Study	27,910.00	143	-	143
Generation	903077024 Interconnection Study	24,763.26	143	-	143
Generation	903077028 Interconnection Study	24,645.73	143	-	143
Generation	903077032 Interconnection Study	24,548.40	143	-	143
Generation	903077037 Interconnection Study	24,291.37	143	-	143
Generation	903077038 Interconnection Study	5,871.69	143	-	143
Generation	903077039 Interconnection Study	25,531.83	143	-	143
Generation	903077040 Interconnection Study	25,441.26	143	-	143
Generation	903077042 Interconnection Study	26,136.03	143	-	143
Generation	903077043 Interconnection Study	25,903.10	143	-	143
Generation	903077044 Interconnection Study	13,977.06	143	-	143
Generation	903077045 Interconnection Study	26,153.09	143	-	143
Generation	903077046 Interconnection Study	15,035.66	143	-	143
Generation	903077048 Interconnection Study	5,871.69	143	-	143
Generation	903077049 Interconnection Study	26,008.07	143	-	143
Generation	903077050 Interconnection Study	8,066.70	143	-	143
Generation	903077051 Interconnection Study	7,331.20	143	-	143
Generation	903077052 Interconnection Study	24,051.92	143	-	143
Generation	903077054 Interconnection Study	5,871.69	143	-	143
Generation	903077055 Interconnection Study	26,512.79	143	-	143
Generation	903077056 Interconnection Study	14,346.85	143	-	143
Generation	903077057 Interconnection Study	5,871.69	143	-	143
Generation	903077058 Interconnection Study	24,460.25	143	-	143
Generation	903077059 Interconnection Study	12,756.79	143	-	143
Generation	903077061 Interconnection Study	14,151.92	143	-	143
Generation	903077062 Interconnection Study	29,617.41	143	-	143
Generation	903077063 Interconnection Study	28,989.00	143	-	143
Generation	903077064 Interconnection Study	9,154.74	143	(8,932.46)	143
Generation	903077065 Interconnection Study	30,289.65	143	-	143
Generation	903077067 Interconnection Study	29,806.06	143	-	143
Generation	903077068 Interconnection Study	27,211.71	143	-	143
Generation	903077069 Interconnection Study	30,290.43	143	-	143
Generation	903077070 Interconnection Study	10,186.92	143	-	143
Generation	903077071 Interconnection Study	28,676.15	143	-	143
Generation	903077073 Interconnection Study	30,103.02	143	-	143
Generation	903077074 Interconnection Study	29,453.88	143	-	143
Generation	903077075 Interconnection Study	31,988.07	143	-	143
Generation	903077076 Interconnection Study	32,251.94	143	-	143
Generation	903077077 Interconnection Study	28,560.60	143	-	143
Generation	903077079 Interconnection Study	30,212.44	143	-	143
Generation	903077080 Interconnection Study	13,232.40	143	-	143
Generation	903077081 Interconnection Study	29,655.19	143	-	143
Generation	903083043 Interconnection Study	3,217.14	143	(3,099.97)	143
Generation	903083877 Interconnection Study	6,115.25	143	(5,884.76)	143
Generation	903085799 Interconnection Study	1,116.84	143	(10,000.00)	143
Generation	903086094 Interconnection Study	2,237.22	143	(2,154.44)	143
Generation	903086095 Interconnection Study	2,453.19	143	(2,370.95)	143
Generation	903088483 Interconnection Study	7,751.89	143	(7,445.69)	143
Generation	903088484 Interconnection Study	3,461.39	143	(3,320.42)	143
Generation	903088485 Interconnection Study	2,998.81	143	(2,920.35)	143
Generation	903088486 Interconnection Study	5,680.28	143	(5,450.99)	143
Generation	903088487 Interconnection Study	4,863.78	143	(4,714.62)	143
Generation	903088488 Interconnection Study	4,253.38	143	(4,080.83)	143

Generation	903088489 Interconnection Study	2,726.30	143	(2,633.72)	143
Generation	903088490 Interconnection Study	2,407.04	143	(2,321.49)	143
Generation	903088699 Interconnection Study	11,850.50	143	(20,000.00)	143
Generation	903088704 Interconnection Study	6,183.14	143	(5,940.61)	143
Generation	903088705 Interconnection Study	2,332.04	143	(2,247.90)	143
Generation	903088706 Interconnection Study	3,497.94	143	(3,399.39)	143
Generation	903089128 Interconnection Study	3,437.84	143	(3,326.02)	143
Generation	903089140 Interconnection Study	4,312.58	143	(4,150.70)	143
Generation	903089201 Interconnection Study	4,710.82	143	(4,604.60)	143
Generation	903089204 Interconnection Study	4,113.56	143	(3,962.77)	143
Generation	903089207 Interconnection Study	7,384.71	143	(7,082.54)	143
Generation	903089208 Interconnection Study	3,062.43	143	(2,939.04)	143
Generation	903089217 Interconnection Study	4,366.57	143	(4,192.73)	143
Generation	903089218 Interconnection Study	3,857.19	143	(3,793.01)	143
Generation	903089276 Interconnection Study	5,197.60	143	(4,995.46)	143
Generation	903089277 Interconnection Study	3,883.11	143	(3,740.18)	143
Generation	903089278 Interconnection Study	5,096.36	143	(4,899.51)	143
Generation	903089359 Interconnection Study	4,969.69	143	(4,768.20)	143
Generation	903089360 Interconnection Study	3,626.65	143	(3,485.24)	143
Generation	903089362 Interconnection Study	3,081.83	143	(2,877.90)	143
Generation	903089363 Interconnection Study	1,552.04	143	(1,497.90)	143
Generation	903089367 Interconnection Study	3,155.42	143	(3,037.41)	143
Generation	903089368 Interconnection Study	3,009.71	143	(2,894.92)	143
Generation	903089594 Interconnection Study	2,862.59	143	(2,746.19)	143
Generation	903089595 Interconnection Study	3,763.36	143	(3,626.47)	143
Generation	903089901 Interconnection Study	2,795.83	143	(2,690.57)	143
Generation	903090109 Interconnection Study	2,593.49	143	(2,505.47)	143
Generation	903090110 Interconnection Study	38.92	143	(205.34)	143
Generation	903090111 Interconnection Study	4,022.57	143	(3,860.92)	143
Generation	903090112 Interconnection Study	4,982.04	143	(4,774.68)	143
Generation	903090113 Interconnection Study	2,611.53	143	(2,511.19)	143
Generation	903090114 Interconnection Study	5,276.59	143	(5,062.18)	143
Generation	903090115 Interconnection Study	3,646.07	143	(3,498.78)	143
Generation	903090116 Interconnection Study	4,162.80	143	(3,990.08)	143
Generation	903090117 Interconnection Study	2,284.15	143	(2,197.56)	143
Generation	903090420 Interconnection Study	5,001.45	143	(4,830.02)	143
Generation	903092105 Interconnection Study	6,266.45	143	(6,015.85)	143
Generation	903092106 Interconnection Study	2,502.15	143	(2,401.93)	143
Generation	903092107 Interconnection Study	4,691.82	143	(4,501.60)	143
Generation	903092959 Interconnection Study	25,651.05	143	(200,000.00)	143
Generation	903092962 Interconnection Study	23,827.72	143	(250,000.00)	143
Generation	903092963 Interconnection Study	24,386.07	143	(200,000.00)	143
Generation	903092967 Interconnection Study	25,232.61	143	(150,000.00)	143
Generation	903092973 Interconnection Study	4,688.46	143	(4,505.10)	143
Generation	903092974 Interconnection Study	3,327.02	143	(3,178.90)	143
Generation	903092975 Interconnection Study	4,979.33	143	(4,792.69)	143
Generation	903093286 Interconnection Study	23,294.02	143	(116,000.00)	143
Generation	903093288 Interconnection Study	22,266.05	143	(72,000.00)	143
Generation	903095399 Interconnection Study	358.37	143	-	143
Generation	903096286 Interconnection Study	18,953.36	143	(150,000.00)	143
Generation	903098477 Interconnection Study	22,443.70	143	(90,000.00)	143
Generation	903098539 Interconnection Study	25,032.64	143	(140,000.00)	143
Generation	903098540 Interconnection Study	1,186.71	143	(51,000.00)	143
Generation	903098541 Interconnection Study	20,260.79	143	(250,000.00)	143
Generation	903098543 Interconnection Study	10,504.21	143	(3,549.05)	143
Generation	903098551 Interconnection Study	8,000.18	143	(127,000.00)	143
Generation	903098817 Interconnection Study	24,774.73	143	(135,000.00)	143
Generation	903099239 Interconnection Study	24,090.76	143	(106,000.00)	143

Generation	903099244 Interconnection Study	8,178.61	143	(20,000.00)	143
Generation	903099245 Interconnection Study	8,178.61	143	(20,000.00)	143
Generation	903100338 Interconnection Study	22,453.75	143	(88,000.00)	143
Generation	903100339 Interconnection Study	9,976.40	143	(20,000.00)	143
Generation	903100459 Interconnection Study	8,178.61	143	(20,000.00)	143
Generation	903102486 Interconnection Study	8,178.61	143	(20,000.00)	143
Generation	903102888 Interconnection Study	26,171.73	143	(106,000.00)	143
Generation	903106658 Interconnection Study	423.91	143	(407.57)	143
Generation	903107956 Interconnection Study	5,859.19	143	-	143
Generation	903107957 Interconnection Study	5,859.19	143	-	143
Generation	903107958 Interconnection Study	5,859.19	143	-	143
Generation	903115215 Interconnection Study	387.79	143	(372.46)	143
Generation	903125751 Interconnection Study	632.60	143	-	143
Generation	903127354 Interconnection Study	3,896.70	143	(3,739.78)	143
Generation	903127885 Interconnection Study	1,608.76	143	(1,543.95)	143
Generation	903127902 Interconnection Study	13,670.56	143	-	143
Generation	903127903 Interconnection Study	15,888.28	143	-	143
Generation	903127904 Interconnection Study	15,586.01	143	-	143
Generation	903127905 Interconnection Study	16,251.69	143	-	143
Generation	903127906 Interconnection Study	13,368.29	143	-	143
Generation	903127907 Interconnection Study	15,586.01	143	-	143
Generation	903127908 Interconnection Study	13,368.29	143	-	143
Generation	903127909 Interconnection Study	15,586.01	143	-	143
Generation	903127910 Interconnection Study	20,471.68	143	-	143
Generation	903127911 Interconnection Study	15,586.01	143	-	143
Generation	903127912 Interconnection Study	7,748.29	143	-	143
Generation	903127913 Interconnection Study	15,586.01	143	-	143
Generation	903127920 Interconnection Study	7,748.29	143	-	143
Generation	903127921 Interconnection Study	7,748.29	143	-	143
Generation	903127922 Interconnection Study	15,586.01	143	-	143
Generation	903127923 Interconnection Study	13,368.29	143	-	143
Generation	903127924 Interconnection Study	16,122.77	143	-	143
Generation	903127925 Interconnection Study	7,748.29	143	-	143
Generation	903127926 Interconnection Study	15,586.01	143	-	143
Generation	903127927 Interconnection Study	15,586.01	143	-	143
Generation	903127928 Interconnection Study	15,586.01	143	-	143
Generation	903127929 Interconnection Study	15,586.01	143	-	143
Generation	903127931 Interconnection Study	15,586.01	143	-	143
Generation	903127932 Interconnection Study	15,586.01	143	-	143
Generation	903127933 Interconnection Study	15,586.01	143	-	143
Generation	903127934 Interconnection Study	7,748.29	143	-	143
Generation	903127935 Interconnection Study	15,586.01	143	-	143
Generation	903127936 Interconnection Study	15,586.01	143	-	143
Generation	903127937 Interconnection Study	15,586.01	143	-	143
Generation	903127938 Interconnection Study	15,586.01	143	-	143
Generation	903127939 Interconnection Study	9,734.54	143	-	143
Generation	903127940 Interconnection Study	7,748.29	143	-	143
Generation	903127941 Interconnection Study	15,586.01	143	-	143
Generation	903127942 Interconnection Study	15,740.46	143	-	143
Generation	903127943 Interconnection Study	15,586.01	143	-	143
Generation	903127944 Interconnection Study	15,586.01	143	-	143
Generation	903127945 Interconnection Study	15,586.01	143	-	143
Generation	903127946 Interconnection Study	15,586.01	143	-	143
Generation	903127947 Interconnection Study	15,586.01	143	-	143
Generation	903127948 Interconnection Study	13,368.29	143	-	143
Generation	903127949 Interconnection Study	15,586.01	143	-	143
Generation	903127950 Interconnection Study	15,586.01	143	-	143
Generation	903127951 Interconnection Study	15,586.01	143	-	143

Generation	903127952 Interconnection Study	7,748.29	143	-	143
Generation	903127953 Interconnection Study	15,586.01	143	-	143
Generation	903127955 Interconnection Study	16,042.88	143	-	143
Generation	903127956 Interconnection Study	15,586.01	143	-	143
Generation	903127957 Interconnection Study	7,748.29	143	-	143
Generation	903127958 Interconnection Study	13,368.29	143	-	143
Generation	903127959 Interconnection Study	13,368.29	143	-	143
Generation	903129088 Interconnection Study	2,305.98	143	(10,000.00)	143
Generation	903129095 Interconnection Study	929.13	143	(10,000.00)	143
Generation	903129101 Interconnection Study	1,401.46	143	(10,000.00)	143
Generation	903129102 Interconnection Study	835.11	143	(10,000.00)	143
Generation	903138460 Interconnection Study	836.58	143	(10,000.00)	143
Generation	903150033 Interconnection Study	411.14	143	(10,000.00)	143
Generation	903153722 Interconnection Study	205.58	143	(10,000.00)	143
Generation	903156213 Interconnection Study	3,020.52	143	-	143
Generation	903162658 Interconnection Study	4,948.95	143	-	143
Generation	903164040 Interconnection Study	1,727.53	143	-	143
Generation	903167347 Interconnection Study	7,711.00	143	-	143
Generation	903168315 Interconnection Study	12,418.52	143	-	143
Generation	903168316 Interconnection Study	5,702.40	143	(10,000.00)	143
Generation	903168407 Interconnection Study	11,969.39	143	-	143
Generation	903168408 Interconnection Study	6,110.00	143	-	143
Generation	903172041 Interconnection Study	-	143	(10,000.00)	143
Generation	903172043 Interconnection Study	-	143	(10,000.00)	143
Generation	903172500 Interconnection Study	7,441.41	143	(10,000.00)	143
Generation	903172501 Interconnection Study	5,313.17	143	(10,000.00)	143
Generation	903177015 Interconnection Study	15,890.80	143	(50,000.00)	143
Generation	903177278 Interconnection Study	632.94	143	-	143
Generation	903177983 Interconnection Study	3,778.70	143	-	143
Generation	903182993 Interconnection Study	364.32	143	-	143
Generation	903183358 Interconnection Study	375.18	143	-	143
Generation	903183829 Interconnection Study	377.87	143	-	143
Generation	903187621 Interconnection Study	5,073.64	143	-	143
Generation	903192604 Interconnection Study	10,994.10	143	(65,000.00)	143
Generation	903196829 Interconnection Study	4,107.63	143	(170,000.00)	143
Generation	903197166 Interconnection Study	817.22	143	-	143
Generation	903198708 Interconnection Study	262.08	143	(70,000.00)	143
Generation	903205767 Interconnection Study	150.60	143	(74,000.00)	143
Generation	903206962 Interconnection Study	160.75	143	-	143
Generation	903206963 Interconnection Study	1,491.27	143	-	143
Generation	903207193 Interconnection Study	1,290.39	143	-	143
Generation	903207194 Interconnection Study	1,290.39	143	-	143
Generation	903207195 Interconnection Study	2,598.59	143	(10,000.00)	143
Generation	903211763 Interconnection Study	2,958.65	143	-	143
Generation	903213693 Interconnection Study	580.47	143	-	143
Generation	903215744 Interconnection Study	-	143	-	143
Generation	903215745 Interconnection Study	453.68	143	(10,000.00)	143
Generation	903216858 Interconnection Study	462.34	143	-	143
Generation	903217420 Interconnection Study	1,263.80	143	(10,000.00)	143
Generation	903222786 Interconnection Study	1,105.36	143	(150,000.00)	143
Generation	903235773 Interconnection Study	2,745.03	143	-	143
Generation	903263205 Interconnection Study	470.85	143	-	143
Generation	903293540 Interconnection Study	429.59	143	-	143
Generation	903293541 Interconnection Study	-	143	(60,000.00)	143
Generation	903293542 Interconnection Study	-	143	(60,000.00)	143
Generation	903254581 Interconnection Study	429.59	143	-	143
	Total Generation	**$ 3,974,538.94**		**$ (4,005,814.32)**	

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

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

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

Column (d) includes refunds that were paid to the Interconnection customer in 2020 resulting from payment 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 Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	4,118,637,748	502,896,808	Various	76,177,743	4,545,356,813
2	FASB 109 gross-up of taxes of flow-through					
3	temporary differences which reverse over time under					
4	various regulatory decisions like D.59926,					
5	D.15-011-021, D.14-12-082 and D.14-11-040. The					
6	amortization period depends on the types of flow-					
7	through temporary differences and there are num-					
8	erous.					
9						
10	Unamortized Cost - Palo Verde Commercial	260,434		406	9,859	250,575
11	Operating Date Adjustment					
12	To recover costs incurred between FERC and					
13	CPUC commercial operating date. (Amortization					
14	Period: 03/1988-07/2046) D.01-01-061					
15						
16	Palo Verde Units 2 & 3	1,047,213		Various	39,642	1,007,571
17	To recover deferred common facilities charges.					
18	(Amortization Period: 09/1986-07/2046) D.01-01-061.					
19						
20	Catastrophic Event Memorandum Account	112,552,773	499,295,035	Various	251,364,642	360,483,166
21	To record costs incurred by SCE associated					
22	with a catastrophic event for restoring utility					
23	service to customers; repairing, replacing, or					
24	restoring damaged utility facilities; and complying					
25	with governmental agency orders. (CPUC: E-4791					
26	and E-3238 and Gov. State of Emergency Letters)					
27						
28	Environmental Clean-up Costs	196,962,614	33,043,336	253	22,134,016	207,871,934
29	To recover ratepayer's portion of environmental					
30	costs (D.94-05-020).					
31						
32	Hazardous Waste Balancing Account	3,590,368	1,621,621	Various	3,880,656	1,331,333
33	To recover collaborative hazardous waste costs					
34	associated with cleaning up certain properties con-					
35	taminated with hazardous substances between the					
36	Company's ratepayers and shareholders					
37	(D.94-05-020).					
38						
39	Environmental Remediation	40,517,221	216,165	253	1,684,808	39,048,578
40	To recover 90% of estimated future environmental					
41	remediation/cleanup costs under a collaborative					
42	agreement (e.g. SCE and other third parties)					
43	D.94-05-020.					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	Unamortized Nuclear Plant	66,825,082		108	4,354,622	62,470,460
2	To reflect Palo Verde Nuclear Plant as a					
3	regulatory asset, D01-01-061.					
4	(Amortization Period: 03/1988-07/2046)					
5						
6	Nuclear Asset Retirement Obligation (ARO)		133,372,962	Various	74,053,226	59,319,736
7	To establish a regulatory asset for decommission-					
8	ing costs collected in rates for Nuclear and coal					
9	ARO property per FAS 143. (Amortization					
10	Period: 12/2003-12/2025)					
11						
12	Leases for Power Contracts	594,296,272	344,001,484	Various	533,570,040	404,727,716
13	To record regulatory asset associated with power					
14	contracts that are subject to lease accounting					
15	rules under the guidance of EITF No. 01-8 and					
16	SFAS 13.(Amortization Period: 12/2006- 4/2026)					
17						
18	Miscellaneous Balancing Account Activity	(200,607,368)	469,701,192	Various	1,020,680,369	-751,586,545
19	To capture various accrued purchased power					
20	agreements and other miscellaneous financial/regul-					
21	atory reserves.					
22						
23	Fire Hazard Prevention Memorandum Account	199,761,211	256,174,505	Various	2,260,924	453,674,792
24	To record the increase in costs incurred related to					
25	fire hazard prevention in compliance with Commis-					
26	sion Decision phase 1 D.09-08-029, phase 2 D.12-					
27	01-032, R. 15-05-006.					
28						
29	Pension Regulatory Asset under SFAS 87 & 158	87,456,071		228	75,243,330	12,212,741
30	To record the cumulative difference between pension					
31	expense calculated for ratemaking purposes and the					
32	amount calculated for accounting purposes since					
33	implementation of SFAS 87 D.06-05-016 and SFAS 158					
34	Employers' Accounting Defined Pension & Other Post-					
35	Retirement Plans (D.06-05-016).					
36						
37	Incurred But Not Reported Medical Claims	12,164,884	28,812,500	182	29,575,410	11,401,974
38	To record a regulatory asset for					
39	estimated costs of medical services rendered for					
40	which claims have not been filed or invoiced					
41	(Incurred But Not Reported) D.09-03-025.					
42						
43						
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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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	Public Purpose Programs Adjustment Mechanism		140,189,714	254	116,329,583	23,860,131
2	To record Public Goods Charge Revenue,					
3	PGC expenses authorized in P.U. Code Section					
4	399.8, and other CPUC Public Purpose Program					
5	revenues and expenses (D. 11-12-038).					
6	Programs include: ESAP, CARE, EPIC, OBF, PEEBA,					
7	LCRPBA, & NSHF.					
8						
9	Agricultural Account Aggregation Study Memorandum	79,365	481	182	79,846	
10	Account					
11	To record the costs, not to exceed $100,000,					
12	associated with a study that will examine the					
13	costs and benefits of agricultural customer					
14	account aggregation. Pursuant to Decision					
15	D.13-03-031, the costs of the study shall					
16	be recovered from Agricultural and Pumping					
17	customers through the distribution sub-account					
18	of the Base Revenue Requirement Balancing					
19	Account (BRRBA).					
20						
21	Mobilehome Park Master Meter Balancing Account		25,634,251	Various	25,634,251	
22	To record actual incremental incurred costs of					
23	implementing the voluntary program to convert the					
24	electric master-meter/submeter service to direct					
25	service at Mobilehome Parks (MHP) and					
26	manufactured housing communities, pursuant to					
27	(D.) 14-03-021.					
28						
29	Litigation Costs Tracking Account	1,742,478	2,580,905	182	3,484,956	838,427
30	In accordance with Resolution E-3894, SCE shall					
31	maintain a Litigation Costs Tracking Account within					
32	the ESMA to track: 1) litigation costs that are					
33	“set-aside” in the FERC investigation settlement					
34	agreements; and 2) actual litigation costs incurred					
35	by SCE. Amounts recorded in the Litigation Costs					
36	Tracking Account shall be subject to audit in SCE's					
37	ERRA proceedings.					
38						
39	Net Energy Metering (NEM) Online Application	1,161,616	32,634	Various	3,039	1,191,211
40	System Memorandum Account					
41	To track the costs SCE incurs to establish an					
42	online application system for processing					
43	applications for interconnection under SCE’s					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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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	NEM tariffs, pursuant to Decision D.14-11-001					
2	and D.16-01-044.					
3						
4	Green Tariff Shared Renewables Admin Cost	610,182	35,038	407	20,576	624,644
5	Memorandum Account					
6	To record the difference between revenues collected					
7	through GTSR adminstrative charge and initial					
8	and on-going incremental administrative costs					
9	(D.15-01-051).					
10						
11	Green Tariff Marketing, Education & Outreach	319,299	2,153	407	51,147	270,305
12	Memorandum Account					
13	To record the difference between revenues					
14	collected through Green Tariff ME&O costs and					
15	initial and on-going incremental ME&O costs					
16	(D.15-01-051).					
17						
18	Greenhouse Gas (GHG) Administrative Costs		388,491	254	388,491	
19	Memorandum Account					
20	To record the initial and on-going administrative					
21	costs incurred in order to implement the					
22	Commission-adopted GHG revenue allocation					
23	methodology, pursuant to D.12-12-033.					
24						
25	Residential Rate Implementation Memorandum Account	30,221,343	21,802,302	Various	14,701,562	37,322,083
26	To record SCE's incremental operation and					
27	maintenance (O&M) costs and capital revenue					
28	requirement associated with complying with the					
29	direction of the Commission in Decision D.15-07-001					
30	and Resolution E-4761 on Residential Rate Reform					
31	and Transition to Time-of-Use (TOU) Rates.					
32						
33	Reliability Service Balancing Account		10,424	Various	10,424	
34	To track the RS revenues and RS costs to ensure					
35	that SCE neither over-collects nor under-collects					
36	RS costs assessed (D.06-05-016).					
37						
38	Mobilehome Park Master Meter Regulatory Asset	59,496,835	16,944,611	Various	15,979,749	60,461,697
39	To record Mobile Home Park Master Meter					
40	property, plant & equipment, and other as					
41	a regulatory asset (D.14-03-021).					
42						
43						
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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1	GHG Revenue Balancing Account		409,745,075	254	358,318,992	51,426,083
2	To record the difference between the amount of GHG					
3	revenue actually returned to customers via rates					
4	and bill credits, and the actual amount of GHG					
5	revenue SCE receives through consigning allow-					
6	ances to the cap and trade auction D.12-12-033.					
7						
8	Building Benchmarking Data Memo Account	833,660	330,808	Various	601,141	563,327
9	To track SCE's incremental costs associated with					
10	maintaining energy usage data and providing this					
11	data to building owners and their agents as					
12	required by Assembly Bill 802. BBDMA shall be					
13	determined in future ERRA applications.					
14						
15	Pole Loading and Deteriorated Pole Balancing	10,556,568	261,991,261	Various	266,018,551	6,529,278
16	Account					
17	To record the difference between recorded capital-					
18	related revenue, operating expenses, and the					
19	authorized revenue requirement authorized by					
20	D.15-11-021.					
21						
22	Energy Resource Recovery Account		628,083,905	Various	628,083,905	
23	To record SCE's ERRA Revenue, Utility Retained					
24	Generation fuel costs, and purchased power related					
25	expenses D.02-10-062.					
26						
27	Gas Cost Adjustment Billing Balancing Account	25,845	4,109	Various	29,952	2
28	Balance composed of Gas Cost Adjustment Clause					
29	which recovers/refunds gas costs on Catalina Island					
30	D.82-04-010.					
31						
32	Local Capacity Requirements Products Balancing		183,319,331	Various	183,319,331	
33	Account					
34	To record local capacity requirements (LCR) request					
35	for offers (RFO) resource costs pursuant to					
36	D.15-11-041 and D.16.05.050.					
37						
38	Charge Ready Program Balancing Account		5,480,909	Various	5,480,909	
39	To record the actual incremental operations and					
40	maintenance (O&M) expense and capital related					
41	revenue requirements associated with Phase 1 of					
42	the Charge Ready Program (CRP) and Market Education					
43	Program pursuant to D.16-01-023.					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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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	Post Employment Benefit Accrual	13,746,757	1,206,224	Various	4,218,805	10,734,176
2	To reflect a regulatory asset for future recovery					
3	of post employment benefits per SFAS 112.					
4						
5	Wheeler North Reef Expansion Project Memo Account	14,191,070	6,940,231	Various	15,847,800	5,283,501
6	To track SCE's costs associated with the WNR Expan-					
7	sion Project pursuant to the Administrative Law					
8	Judge's Ruling Granting SCE's Motion to Establish					
9	a Memorandum Account Subject to Conditions Set					
10	Forth Herein and Commission Approval of Final					
11	Decision in this Proceeding (Application					
12	(A.) 16-12-002) dated May 1, 2017.					
13						
14	NEM-A Billing Automation Costs Memo Account	369,149	138,023	Various	9,091	498,081
15	To track the costs that SCE incurs to automate Net					
16	Energy Metering Automation (NEM-A) in its billing					
17	system and produce automated bills for customers					
18	electing to participate in NEM-A over the course of					
19	one year, pursuant to Resolution E-4881.					
20						
21	Enhanced Community Renewables Marketing, Education	26,094	17,196	182		43,290
22	& Outreach Memo Account					
23	To record the difference between the revenues					
24	collected through the ECR ME&O Charge and initial					
25	and on-going incremental ME&O costs incurred in					
26	order to implement the Commission-adopted ECR					
27	program, pursuant to D.15-01-051.					
28						
29	Regulatory Asset Fire Insurance	65,348,934	32,675,951	Various	3,095,181	94,929,704
30	To record regulatory asset for non-incremental					
31	wildfire insurance costs.					
32						
33	Emergency Customer Protection Memo Account	123,526	20,070	Various		143,596
34	To record costs associated with customer pro-					
35	tections pursuant to Resolution M-4833.					
36						
37	Integrated Distributed Energy Resources Adm Costs	260,512	61,372	182		321,884
38	Memo Account					
39	To record solicited-related incremental adminis-					
40	trative costs associated with the Utility					
41	Regulatory Incentive Pilot as adopted in					
42	Decision 16-12-036.					
43						
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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	Power Charge Indifference Adjustment Memo Account	47,852	334	182		48,186
2	To record and track the costs associated with the					
3	educaiton and outreach effort for California					
4	Alternate Rate for Energy (CARE) and Medical Base-					
5	line (MB) program customers impacted by the					
6	elimination of the exemption from paying the PCIA					
7	per Decision 18-07-009.					
8						
9	Wildfire Expense Memo Account	455,909,822	1,036,669,305	407	707,954,848	784,624,279
10	To track all amounts paid as a result of wildfire,					
11	and that were not previously authorized in the					
12	SCE's General Rate Case (GRC), per Decision					
13	D.18.11-051.					
14						
15	Transportation Electrification Portfolio Balancing		4,336,567	Various	4,336,567	
16	Account					
17	To record the actual Operations and Maintenance					
18	(O&M) expenses and capital-related revenue require-					
19	ments (i.e. depreciation, return on rate base, and					
20	applicable taxes) associated with the approved					
21	Transportation Electrification Priority Review					
22	Projects (PRPs). Separate subaccounts are estab-					
23	lished in the TEPBA to ensure that SCE will only					
24	recover the revenue requirements assoicated with up					
25	to the total capped level of authorized funding for					
26	each of the individual PRPs and SCE's share of					
27	evaluation costs, pursuant to D.18-01-024.					
28						
29	Distribution Resources Plan Demonstration Balancing	12,483	87	182		12,570
30	Account					
31	To record revenue requirements associated in					
32	Operations & Maintenance (O&M) expenses and capital					
33	expenditures for SCE's Demonstration Project C as					
34	authorized in D.17-02-007.					
35						
36	Demand Response Program Balancing Account		1,297,257	254	1,297,257	
37	To support SCE's recovery of expenses related to					
38	its demand response programs recorded in the					
39	Demand Response Program Balancing Account					
40	(DRPBA). The Resolution granted SCE its proposed					
41	budget for additional improvements in direct parti-					
42	cipation demand response implementation including					
43	development of Click-Through, activities to help i					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

OTHER REGULATORY ASSETS (Account 182.3)

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1	increase enrollments in third party demand reponse					
2	programs, and costs for increasing customer					
3	registrations in the CAISO wholesale market per					
4	E3774 D.18-05-041.					
5						
6	CARE Balancing Account					
7	To reflect in rates, through application of the		113,329,647	Various	3,774,305	109,555,342
8	Public Purpose Program Charge the costs					
9	associated with the CARE Program as authorized					
10	in various CPUC Decisions (D.89-07-062, 89-09-044,					
11	92-06-060, 94-12-049 and 95-10-047).					
12						
13	Green Tariff Shared Renewables Balancing Account	41,896	25,877	407	67,773	
14	To record the difference between the actual revenue					
15	requirements, based on recorded GTSR commodity-					
16	related costs, and the revenues collected from					
17	individual customers electing to participate in the					
18	GTSR Program through charges set to collect					
19	these costs (D.15-01-051).					
20						
21	Aliso Canyon Energy Storage Balancing Account		11,911,082	Various	11,911,082	
22	To record the Tesla and General Electric projects'					
23	actual revenue requirements. The ACESBA will					
24	separately account for and record the revenue					
25	requirements for the Tesla projects and the General					
26	Electric projects per decision D.18-06-027.					
27						
28	Transmission Revenue Balancing Account	5,049,062	14,085,134	407	19,134,196	
29	To record transmission revenue credits, congestion					
30	revenue, wheeling revenue, sale of an FTR revenue,					
31	and ancillary service expense to the TRBAA.					
32	Authorized by ER18-154-000					
33						
34	Purchase Power Settlements	28,812,500	28,812,500	182	57,625,000	
35	Termination of purchase power contracts.					
36						
37	Transmission Access Charge Balancing Account	92,869,162	89,278,929	407	92,962,992	89,185,099
38	To track the flow through to end-use customers					
39	the net cost-shift billed to SCE by the ISO under					
40	the Transmission Access Charge (TAC), ER17-					
41	1345-000.					
42						
43						
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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OTHER REGULATORY ASSETS (Account 182.3)

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1	Medical Balancing Account	357,250	72,019,139	Various	72,376,389	
2	To record the difference between the authorized and					
3	recorded Medical, Dental, Vision expenses in					
4	accordance with D.09-03-025.					
5						
6	Portfolio Allocation Balancing Account	537,490,179	966,696,438	Various	1,068,931,910	435,254,707
7	To determine and pro-ratably recover from respons-					
8	ible bundled service and departing load customers					
9	the "above-market" costs of all generation re-					
10	sources that are eligible for cost recovery through					
11	the competition Transition charge (CTC) and					
12	Power Charge Indifference Adjustment (PCIA) rates,					
13	per decision D.18-10-019.					
14						
15	Tax Accounting Memo Account (TAMA) Expanded	22,718,251	272,652,534	Various	295,370,785	
16	To extend all of the applicable provisions of TAMA					
17	to include 2018 through 2020 and remain open					
18	until the IRS and CFTB audit period for those years					
19	are closed, per decision D.19-05-020.					
20						
21	Tree Mortality Non-Bypassable Charge BA	71,075,256	9,493,548	Various	79,833,076	735,728
22	To record the "net costs" as defined in Decision					
23	D.18-12-003, of biomass generation procured					
24	pursuant to Resolution E-4470 and Resolution E-4805					
25	(Tree Mortality Resources).					
26						
27	Customer Service RePlatform Memo Account	11,133,022	20,171,704	Various	956,607	30,348,119
28	To record the difference between the revenues					
29	collected that opt-out of a wireless smart meter					
30	and the costs incurred resulting from this opt-out					
31	election, excluding related exit-fee costs, per					
32	decision D.19-05-020.					
33						
34	Short Term Incentive Plan Memorandum Account		32,666,132	Various	32,666,132	
35	To track the difference between authorized and					
36	recorded results Results Sharing expenses paid out,					
37	pursuant to D. 06-05-016.					
38						
39	Post Employement Benefits Other than Pensions	3,778,233	5,670,067	Various	9,448,300	
40	(PBOP) Costs Balancing Account					
41	To record the difference between PBOP costs					
42	authorized by the Commission and recorded PBOP					
43	expenses, pursuant to D.06-05-016.					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	Fire Risk Mitigation Memorandum Account	7,501,875	12,933,707	Various		20,435,582
3	To track costs incurred for fire risk mitigation					
4	not otherwise covered in SCE's revenue require-					
5	ments, pursuant to AL 3936-E-A.					
6						
7	Wildfire Mitigation Plan Memorandum Account	265,639,078	263,932,517	Various	2,772,585	526,799,010
8	The WMPMA is to track costs incurred to implement					
9	SCE's Wildfire Mitigation Plan (WMP) that are not					
10	currently reflected in revenue requirements being					
11	paid by customers in rates, and that are also not					
12	being tracked in another existing Commission-					
13	authorized memorandum account, Pursuant to					
14	D.19-05-038.					
15						
16	Clean Energy Optimization Pilot Balancing Account	87,951		254	87,951	
17	The Clean Energy Optimization Pilot Balancing					
18	Account (CEOPBA) is to record the transfer of funds					
19	from the Greenhouse Gas Revenue Balancing Account					
20	(GHGRBA), and to record CEOP performance payments					
21	and administrative costs. SCE will not record					
22	costs in excess of the $20.4 million cap. Upon					
23	completion of the CEOP, SCE shall return any un-					
24	spent CEOP funds to the GHGRBA. Pursuant to					
25	decision D.19-04-010.					
26						
27	New System Gen Balancing Account	85,135,376	280,487,984	Various	365,623,360	
28	The New System Gen Balancing Account records the					
29	costs and benefits of new generation (including any					
30	associated nonbypassable charges collected).					
31	Pursuant to decision D.07-09-044.					
32						
33	Grid Safety & Resiliency Prog Memo Account	29,773,474	129,950,017	Various	159,723,491	
34	The Grid Safety and Resiliency Program Memorandum					
35	Account (GSRPMA) permits SCE to track its Grid					
36	Safety and Resiliency Program (GSRP) costs					
37	costs pursuant to decision D.19-01-019.					
38						
39	California Consumer Privacy Act Memorandum Account	55,888	2,762,673	182		2,818,561
40	The California Consumer Privacy Act Memorandum					
41	Account allows SCE to record and track the incre-					
42	mental Operations and Maintenance (O&M) expenses					
43	and capital-related revenue requirements assoc-					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	iated with capital expenditures for the implemen-					
2	tation of California Consumer Privacy Act of 2018.					
3						
4	Community Solar Green Tariff Balancing Account	95,326		254	95,326	
5	The Community Solar Green Tariff Balancing Account					
6	record all costs related to the implementation and					
7	operation of this program which promotes solar dis-					
8	tributed generation in disadvantaged communities.					
9						
10	Disadvantaged Communities-Green Tariff Balancing	95,326		254	95,326	
11	Account					
12	Disadvantaged Communities-Green Tariff Balancing					
13	Account records all costs related to the implemen-					
14	tation and operation of this program which promotes					
15	solar distributed generation in disadvantaged					
16	communities.					
17						
18	Water Revenue Adjustment Mechanism / Modified Costs	220,894	2,702,795	Various	2,923,689	
19	Balancing Account					
20	The Water Revenue Adjustment Mechanism / Modified					
21	Cost Balancing Account records the difference be-					
22	tween SCE’s authorized sales revenue and actual re-					
23	corded revenue collected through sales and also					
24	records the difference between authorized variable					
25	production expense and the actual variable product-					
26	ion expense incurred.					
27						
28	FERC Formula Rate	55,884,687	588,905,434	Various	574,305,217	70,484,904
29	Records the difference between billed and unbilled					
30	revenue and the recorded transmission revenue					
31	requirement to cover the costs of owning and oper-					
32	ating transmission facilities under ISO control,					
33	per FERC Formula Rate Protocols ER11-3697.					
34						
35	CPUC Deficient Deferred Taxes & Gross-Up TCAJA	742,340,011	25,433	Various	53,339,389	689,026,055
36	To record the CPUC-related difference in accumul-					
37	ated deferred tax balances as a result of the re-					
38	duction of the federal income tax rate by the Tax					
39	Cuts And Job Acts to 21% from the previous 35%					
40	and the related tax gross-up that will be refunded					
41	to/recovered from customers. This represents the					
42	deficient deferred taxes that will be recovered					
43	from ratepayers over the life of the underlying					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	asset that gave rise to the deferred taxes.					
2						
3	FERC Deficient Deferred Taxes-TCAJA	101,819,399		Various	8,433,785	93,385,614
4	To record the FERC-related difference in accumulat-					
5	ed deferred tax balances as a result of the reduct-					
6	ion of the federal income tax rate by the Tax Cuts					
7	And Jobs Act to 21% from the previous 35% and the					
8	related tax gross-up that will be refunded to/re-					
9	covered from customers. This represents the					
10	deficient deferred taxes that will be recovered					
11	from ratepayers over the life of the underlying					
12	asset that gave rise to the deferred taxes.					
13						
14						
15						
16	FERC Deficient Deferred Tax Gross-Up-TCAJA	39,564,228		Various	3,277,138	36,287,090
17	This is to record the gross-up portion of FERC					
18	deficient deferred taxes.					
19						
20	Disadvantaged Communities Singlefamily Solar Homes		152,617	419	194	152,423
21	MA					
22	The purpose of the Disadvantaged Communities					
23	Single-family Solar Homes (DAC-SASH) Memorandum					
24	Account (DACSASHMA) is to track the startup					
25	costs for the DAC-SASH program, as authorized					
26	in Ordering Paragraph10 of D.18-06-027.					
27						
28	Base Revenue Requirement Balancing Account		6,097,325,113	407	5,433,138,665	664,186,448
29	To record the difference between the commission-					
30	authorized base distribution and generation revenue					
31	requirements and the recorded retail distribution					
32	and generation revenues, pursuant to D.04-07-022.					
33						
34	Power Charge Indifference Adjustment Under-		65,960,993	182	2,816,151	63,144,842
35	collection Balancing Account					
36	Establishment of the Power Charge Indifference					
37	Adjustment Undercollection Balancing Account					
38	and Trigger Mechanism in Compliance with Decision					
39	18-10-019. Account tracks any obligation that					
40	accrues fro departing load customers due to the use					
41	of PCIA rate cap.					
42						
43						
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	Service Center Modernization Project Memo Account		7,455,410	182	1,727,691	5,727,719
2	To record the service centers modernization					
3	projects' actual revenue requirements. The SCMPMA					
4	will separately account for and record the revenue					
5	requirements for the six service centers mondern-					
6	ization projects per decision D.19-05-020.					
7						
8	Department of Energy Litigation Memorandum Account		817,428	182		817,428
9	Established in AL 2085-E to record: (1) SCE's					
10	incremental litigation-related costs; and (2)					
11	proceeds received by SCE from the federal govern-					
12	ment for breaching certain Standard Contracts					
13	between SCE and DOE for DOE to dispose of					
14	San Onofre Nuclear Generating Stations (SONGS)					
15	spent nuclear fuel.					
16						
17	COVID-19 Pandemic Protections Memo Account		134,582,809	182		134,582,809
18	To track incremental O&M and capital revenue					
19	requirements related to COVID-19.					
20						
21	CEMA-COVID 19		64,799,188	182	10,679,152	54,120,036
22	To record incremental costs related to comliance					
23	pandemic.					
24						
25	Bilateral Energy & Gas Financial Instruments		43,209,752	Various	43,209,752	
26	To record the mark-to-market adjustments related					
27	to the financial instruments used to hedge power					
28	purchases and natural gas costs for utility					
29	owned generators.					
30						
31	Misc. LT Asset-FERC Recovery-WF Accrual		2,739,538	182		2,739,538
32	To properly track and reconcile wildfire accruals					
33	and payments going forward. Regulatory Accounting					
34	will separately track and monitor the outstanding					
35	reservce balance in FERC WF Reserve Account.					
36						
37	Distributed Generation Statistics Contractor Memo		246,649	182	67,118	179,531
38	Account					
39	The purpose of the Distributed Generation					
40	Statistics Contractor Memorandum Account (DGSCMA)					
41	is to record costs associated with oversight					
42	for work required to maintain the California					
43	Distributed Generation Statistics Website.					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	Electric Program Investment Charge-CEC, SCE, and		907,845	182	855,679	52,166
3	CPUC					
4	To record authorized administrative and program					
5	EPIC revenue requirements and related program					
6	SCE expenses and authorized program					
7	payments to CEC and CPUC per advice letter					
8	2747-E dated June 25, 2012.					
9						
10	Integrated Resources Planning Costs Memo Account		549,829	182		549,829
11	To record SCE's share of the costs incurred by the					
12	Commission related to integrated resource planning					
13	(IRP) third party technical support. These costs					
14	may be recorded upon reimbursement to the Commis-					
15	sion for later recovery in distribution rates from					
16	all customers.					
17						
18	Building Decarbonization Pilot Program Admin		37,404	Vairous	37,404	
19	Costs BA					
20	To record SCE’s costs associated with its role as					
21	contracting agent for the Technology and Equipment					
22	for Clean Heating (TECH) program per advice					
23	letter 4188-E dated April 10, 2020.					
24						
25	Grid Safety & Resiliency Program Balancing Account		596,067,798	182	580,312,861	15,754,937
26	To record actual O&M and capital revenue require-					
27	ment associated witht he Grid Safety & Resiliency					
28	Program per advice letter 4197-E dated					
29	April 22, 2020.					
30						
31	Statewide Marketing Education & Outreach Balancing		11,845,994	182	11,845,994	
32	Account					
33	To record the difference between the Commission-					
34	authorized Statewide Marketing, Education &					
35	Outreach funding and the actual recorded State-					
36	wide ME&O costs per advice letter 4156-E dated					
37	February 4, 2020.					
38						
39	System Reliability Procurement Memorandum Account		554,441	182		554,441
40	The purpose is to track procurement costs and					
41	benefits incurred and received as a result of					
42	D.19-11-016 that ordered SCE to procure an					
43	allocated amount of system resource adequacy (RA)					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	megawatts for its bundled service customers and of					
2	load-serving entities per advice letter 4218-E					
3	dated May 22, 2020.					
4						
5	Residential Disconnections Implementation Cost		11,058	182		11,058
6	Memorandum Account					
7	To track only incremental costs associated with					
8	implementing the requirements in D.20-06-003,					
9	pursuant to OP 95. SCE will track only increment-					
10	al implementation costs, associated with billing					
11	system upgrades, development of the Low-Income					
12	Home Energy Assistance Program online portal,					
13	customer outreach costs, arrearage management					
14	plan and other costs.					
15						
16	Residential Uncollectible Balancing Account		14,937,809	903	14,937,809	
17	The RUBA will record the difference (positive or					
18	negative) between the recorded uncollectibles					
19	expense for all custome groups and the total					
20	authorized uncollectibles revenue collected from					
21	all customers subject to a cap equal to the actual					
22	recorded uncollectibles expense for residential					
23	customers.					
24						
25	Avoided Cost Calculator Memorandum Account		215,184	182		215,184
26	The purpose of the ACCMA is to record SCE's					
27	portion of costs reimbursed to the Commission or					
28	their contractor for updating the Avoided Cost					
29	Calculator and providing technical assistance or					
30	research for the purpose of advancing future					
31	refinement of cost-effective methods pursuant					
32	to D.16-06-007.					
33						
34	Net Energy Metering Measurement and Evalulation		386,123	182		386,123
35	Balancing Account					
36	The purpose of the Net Energy Metering Measure-					
37	ment and Evaluation Balancing Account (NEMMEBA)					
38	is to record costs associated with the measurement					
39	and evaluation of the NEM successor tariff program.					
40	Pursuant to D.18-09-044, Ordering Paragraph					
41	(OP) 13, SCE is authorized to collect its propor-					
42	tionate share of the $2 million budget for costs					
43	associated with measurement and evaluation of the					
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	program.					
2						
3	Vehicle-Grid Integration Working Group Facilitator		127,477	182		127,477
4	Memorandum Account					
5	The purpose of the Vehicle-Grid Integration (VGI)					
6	Working Group Facilitator Memorandum Account					
7	(VGIWGFMA) is to track costs associated with hiring					
8	a technical facilitator for a six-month period,					
9	with possible extension, that will organize and					
10	facilitate the interagency VGI Working Group.					
11	Facilitator costs allocated to each Investor Owned					
12	Utility will be determined through a co-funding					
13	agreement between Southern California Edison (SCE),					
14	Pacific Gas & Electric (PG&E), and San Diego					
15	Gas & Electric (SDG&E).					
16						
17						
18	Rounding Adjustment	(1)				-1
19						
20						
21						
22						
23						
24						
25						
26						
27						
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42						
43						
44	TOTAL	7,990,086,236	15,010,518,377		13,465,689,515	9,534,915,098

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	04/14/2021	End of 2020/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	2,270,642	2,275,481	Various	3,141,806	1,404,317
2	(Amort. Period:04/2016-3/2023)					
3	OWIP - ECS Def Debit	13,087,169	12,566,539	Various	13,398,263	12,255,445
4						
5	Plant Claims Pending	7,129,662	1,026,011	Various	8,155,673	
6						
7	SLU Def Proj Cost	35,698				35,698
8						
9	SONGS Nuc Fuel Stor./Other Cost	17,328,120	1,003,146	Various	17,086,242	1,245,024
10						
11	OBF Loan Payment	7,406	309,129	Various	93,747	222,788
12	Wildfire Insurance Fund Contr.	2,767,255,003		925.9	323,773,506	2,443,481,497
13	(Amort. Per. 7/2019 to 7/2029)					
14	PVRR Pole Contra	-40,031,315	40,031,315	Various		
15						
16	Misc. Deferred Debits	513,018	1,524,635	Various	686,693	1,350,960
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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32						
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34						
35						
36						
37						
38						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	50,731,184				68,328,894
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	2,818,326,587				2,528,324,623

Schedule Page: 233 Line No.: 12 Column: a

Wildfire Insurance Fund Contributions.

Schedule Page: 233 Line No.: 14 Column: a

The PVRR (Present Value Revenue Requirement) Pole contra deferred debit is based on the 2018 GRC decision on the SPIDA (pole software analysis tool) pole replacement cost disallowance.

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	04/14/2021	End of 2020/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Attached Schedule	2,364,830,749	3,985,081,394
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,364,830,749	3,985,081,394
9	Gas		
10	See Attached Schedule	142,393	145,794
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	142,393	145,794
17	Other Income	9,549,153	3,482,683
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,374,522,295	3,988,709,871

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 Issurance Cost	539,260	449,174
190	Executive Incentive Comp	1,227,871	435,338
190	Bond Discount Amort	719,009	675,252
190	Executive Incentive Plan	1,264,409	557,015
190	Ins - Inj/Damage Prov	28,272,451	29,668,055
190	Accrued Vacation	13,313,776	41,227,598
190	Amortization of Debt Expense	815,253	430,704
190	Wildfire Reserve - Pre 2019	814,158,069	1,044,817,531
190	Wildfire Reserve - Post 2018	4,613,096	13,350,976
190	Decommissioning	466,893,649	532,905,125
190	Pension & PBOP	37,050,591	32,996,506
190	Property/Non-ISO	751,622,202	713,815,141
190	Regulatory Assets/Liab	57,713	202,184,045
190	Temp-Other/Non-ISO	(70,476,892)	629,081,739
190	Net Operating Loss DTA	314,760,292	742,487,195
	Total Electric	2,364,830,749	3,985,081,394

Schedule Page: 234 Line No.: 10 Column: a

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS:			
190	Property/Non-ISO	145,794	145,794
190	Temp-Other/Non-ISO	(3,401)	-
	Total Gas	142,393	145,794

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER INCOME:			
190	Temp - Other/Non-ISO	(1,683,831)	2,777,222
190	Property/Non-ISO	10,334,183	(201,447)
190	EMS	898,801	906,909
	Total Other	9,549,153	3,482,683

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	04/14/2021	End of 2020/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock, no par value	560,000,000		
3	Total Common Stock	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		
19				
20				
21	Preference Stock			
22	No Par Value	50,000,000		
23				
24	Non-Voting and Cumulative			
25				
26	6.250% SERIES E		1,000.00	1,000.00
27	5.100% SERIES G		2,500.00	2,500.00
28	5.750% SERIES H		2,500.00	2,500.00
29	5.375% SERIES J		2,500.00	2,500.00
30	5.450% SERIES K		2,500.00	2,500.00
31	5.000% SERIES L		2,500.00	2,500.00
32	Total Preferred and Preference Stock	86,000,000		
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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
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						20
						21
						22
						23
						24
						25
350,000	350,000,000					26
88,004	220,010,000					27
110,004	275,010,000					28
130,004	325,010,000					29
120,004	300,010,000					30
190,004	475,010,000					31
988,020	1,945,050,000					32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Schedule Page: 250 Line No.: 21 Column: a

SCE has authorization from CPUC to issue up to $1.42 billion additional preferred equity.

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	04/14/2021	End of 2020/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	5,432,335,845

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	04/14/2021	End of 2020/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	5,432,335,845

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	04/14/2021	End of 2020/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.
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(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	5,432,335,845

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		
19	Stock-based Compensation (2016)	9,959,128
20		
21	Excess Tax Benefit Related to Stock Based Awards (2016)	-458,168
22		
23	Stock-based Compensation (2017)	10,912,673
24		
25	Stock-based Compensation (2018)	9,906,841
26		
27	Stock-based Compensation (2019)	8,992,918
28		
29	Edison International Capital Contribution (2019)	3,250,000,000
30		
31	Stock-based Compensation (2020)	8,615,327
32		
33	Edison International capital contribution (2020)	1,432,000,000
34		
35		
36		
37		
38		
39		
40	TOTAL	5,432,335,845

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	04/14/2021	End of 2020/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	
4		
5		
6		
7		
8		
9	Preference Stock	
10		
11		
12	6.250% SERIES E	5,957,289
13	5.100% SERIES G	7,134,904
14	5.750% SERIES H	6,272,358
15	5.375% SERIES J	6,419,578
16	5.450% SERIES K	6,959,810
17	5.000% SERIES L	12,800,620
18		
19		
20		
21		
22	TOTAL	45,647,715

Schedule Page: 254 Line No.: 3 Column: b

During 2020, SCE redeemed all of the outstanding preferred stock.

Schedule Page: 254 Line No.: 13 Column: b

During 2020, SCE redeemed 72,000 shares of Series G preference shares.

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	04/14/2021	End of 2020/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:			
2	First and Refunding Mortgage Bonds:			
3	Series 2004B	6.000%	525,000,000	4,809,750
4				3,470,250 D
5	Series 2004G	5.750%	350,000,000	3,062,500
6				154,000 D
7	Series 2005B	5.550%	250,000,000	2,341,346
8				732,500 D
9	Series 2005E	5.350%	350,000,000	3,062,500
10				168,000 D
11	Series 2006A	5.625%	350,000,000	3,430,000
12				857,500 D
13	Series 2006E	5.550%	400,000,000	4,000,000
14				2,176,000 D
15	Series 2008A	5.950%	600,000,000	6,350,000
16				2,760,000 D
17	Series 2009A	6.050%	500,000,000	4,095,000 D
18				4,375,000
19	Series 2010A	5.500%	500,000,000	6,015,000 D
20				5,350,000
21	Series 2010B	4.500%	500,000,000	3,180,000 D
22				5,325,000
23	Series 2011A	3.875%	500,000,000	2,885,000 D
24				4,285,000
25	Series 2011E	3.900%	250,000,000	1,405,000 D
26				2,712,500
27	Series 2012A	4.050%	400,000,000	4,728,000 D
28				4,300,190
29	Series 2013A	3.900%	400,000,000	2,388,000 D
30				4,321,820
31	Series 2013C	3.500%	600,000,000	1,056,000 D
32				5,213,033
33	TOTAL		17,717,031,347	148,177,983

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	04/14/2021	End of 2020/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	First and Refunding Mortgage Bonds			
3				
4	Series 2013D	4.650%	800,000,000	5,504,000 D
5				8,347,631
6	Series 2015A	1.845%	550,000,000	4,452,468
7				
8	Series 2015B	2.400%	325,000,000	22,750 D
9				2,644,788
10	Series 2015C	3.600%	425,000,000	1,632,000 D
11				4,677,785
12	Series 2017A	4.000%	1,800,000,000	18,956,420
13				-53,753,000 P
14				490,000 D
15	Series 2018A	2.900%	450,000,000	1,906,478
16				189,000 D
17	Series 2018B	3.650%	400,000,000	3,305,768
18				728,000 D
19	Series 2018C	4.125%	1,300,000,000	13,389,459
20				33,058,500 D
21	Series 2018D	3.400%	300,000,000	2,238,406
22				312,000 D
23	Series 2018E	3.700%	900,000,000	7,127,941
24				-15,870,000 P
25				642,000 D
26	Series 2019A	4.200%	500,000,000	4,159,091
27				2,005,000 D
28	Series 2019B	4.875%	600,000,000	6,340,909
29				924,000 D
30	Series 2019C	2.850%	500,000,000	4,116,667
31				-1,179,000 P
32				620,000 D
33	TOTAL		17,717,031,347	148,177,983

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.
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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	Series 2020A	3.650%	1,200,000,000	12,772,727
2				-38,227,000 P
3				3,265,000 D
4	Series 2020B	2.250%	400,000,000	3,327,273
5				380,000 D
6	Series 2020C	1.200%	350,000,000	2,680,000
7				665,000 D
8				
9	OTHER LONG TERM DEBT:			
10				
11	SONGS_2006B	1.900	38,500,000	325,161
12				
13	Series 2006C&D	2.625	135,000,000	2,490,033
14				
15	Clark County 2010	1.875	75,000,000	873,795
16				
17	4CRNRS 2011	1.875	55,540,000	994,726
18				
19	Series PV 2000AB	5.000	144,400,000	1,300,000
20				
21	Series 4CRNRS 05AB	1.875	203,460,000	2,271,452
22				
23	SONGS 2010A	4.500	100,000,000	2,000,000
24	SUBTOTAL ACCOUNT 221		18,026,900,000	151,116,117
25				
26	ACCOUNT 222 (REACQUIRED BONDS)			
27				
28	SONGS_2006B	1.900%	-38,500,000	-325,161
29				
30	CLARK COUNTY 2010	1.875%	-75,000,000	-873,795
31				
32	4CRNRS 2011	1.875%	-55,540,000	-994,726
33	TOTAL		17,717,031,347	148,177,983

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	04/14/2021	End of 2020/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)		Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1				
2	Series PV 2000AB	5.000%	-144,400,000	-1,300,000
3				
4	Series 4CRNRS 05AB	1.875%	-203,460,000	-2,271,452
5				
6	SONGS 2010A	4.500%	-100,000,000	-2,000,000
7				
8	SUBTOTAL ACCOUNT 222		-616,900,000	-7,765,134
9				
10	ACCOUNT 224-Other Long-Term Debt			
11	6.65% Notes	6.650%	300,000,000	1,212,000
12				3,615,000 D
13	Ft. Irwin Loan	5.060%	7,031,347	
14				
15	Capitalized Interest Related to Nuclear Fuel			
16				
17	SUBTOTAL Account 224		307,031,347	4,827,000
18				
19	Rounding Adjustment			
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33	TOTAL		17,717,031,347	148,177,983

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
01/14/04	01/15/34	01/14/04	01/15/34	525,000,000	31,500,000	3
						4
03/23/04	04/01/35	03/23/04	04/01/35	350,000,000	20,125,000	5
						6
01/19/05	01/15/36	01/19/05	01/15/36	250,000,000	13,875,000	7
						8
06/27/05	7/15/35	6/27/05	07/15/35	350,000,000	18,725,000	9
						10
01/31/06	02/01/36	01/31/06	02/01/36	350,000,000	19,687,500	11
						12
12/11/06	01/15/37	12/11/06	01/15/37	400,000,000	22,200,000	13
						14
01/22/08	02/01/38	01/22/08	02/01/38	600,000,000	35,700,000	15
						16
03/20/09	03/15/39	03/20/09	03/15/39	500,000,000	30,250,000	17
						18
3/11/10	03/15/40	03/11/10	03/15/40	500,000,000	27,500,000	19
						20
08/30/10	09/01/40	08/30/10	09/01/40	500,000,000	22,500,000	21
						22
05/17/11	06/01/21	05/17/11	06/01/21	500,000,000	19,375,000	23
						24
11/22/11	12/01/41	11/22/11	12/01/41	250,000,000	9,750,000	25
						26
03/13/12	03/15/42	03/13/12	03/15/42	400,000,000	16,200,000	27
						28
03/07/13	03/15/43	03/07/13	03/15/43	400,000,000	15,600,000	29
						30
10/02/13	10/01/23	10/02/13	10/01/23	600,000,000	21,000,000	31
						32
				17,284,202,616	721,798,639	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	04/14/2021	End of 2020/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
10/02/13	10/01/43	10/02/13	10/01/43	800,000,000	37,200,000	4
						5
01/26/15	02/01/22	01/26/15	02/01/22	117,857,143	2,657,679	6
						7
01/26/15	02/01/22	01/26/15	02/01/22	325,000,000	7,800,000	8
						9
01/26/15	02/01/45	01/26/15	02/01/45	425,000,000	15,300,000	10
						11
03/24/17	04/01/47	03/24/17	04/01/47	1,800,000,000	72,000,000	12
						13
						14
03/05/18	03/01/21	03/05/18	03/01/21	450,000,000	13,050,000	15
						16
03/05/18	03/01/28	03/05/18	03/01/28	400,000,000	14,600,000	17
						18
03/05/18	03/01/48	03/05/18	03/01/48	1,300,000,000	53,625,000	19
						20
06/04/18	06/01/23	06/04/18	06/01/23	300,000,000	10,200,000	21
						22
08/02/18	08/01/25	08/02/18	08/01/25	900,000,000	27,688,333	23
						24
						25
03/15/19	03/01/29	03/15/19	03/01/29	500,000,000	21,000,000	26
						27
03/15/19	03/01/49	03/15/19	03/01/49	600,000,000	29,250,000	28
						29
08/06/19	08/01/29	08/06/19	08/01/29	500,000,000	14,186,667	30
						31
						32
				17,284,202,616	721,798,639	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	04/14/2021	End of 2020/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
1/9/20	2/1/50	1/9/20	2/1/50	1,200,000,000	38,568,333	1
						2
						3
3/9/20	6/1/30	3/9/20	6/1/30	400,000,000	7,300,000	4
						5
10/1/20	2/1/26	10/1/20	2/1/26	350,000,000	1,050,000	6
						7
						8
						9
						10
4/5/13	4/1/28	4/5/13	4/1/28	38,500,000	182,875	11
						12
4/12/06	11/1/33	4/12/06	11/1/33	135,000,000	3,543,750	13
						14
4/1/15	6/1/31	4/1/15	6/1/31	75,000,000	351,563	15
						16
4/1/15	4/1/29	4/1/15	4/1/29	55,540,000	260,344	17
						18
3/1/04	6/1/35	3/1/04	6/1/35	144,400,000	5,354,833	19
						20
4/1/15	4/1/29	4/1/15	4/1/29	203,460,000	953,719	21
						22
9/21/10	9/1/29	9/21/10	9/1/29	100,000,000	3,200,000	23
				17,594,757,143	703,310,596	24
						25
						26
						27
04/05/13	04/01/28	04/05/13	04/01/28	-38,500,000		28
						29
04/01/15	06/01/31	04/01/15	06/01/31	-75,000,000		30
						31
04/01/15	04/01/29	04/01/15	04/01/29	-55,540,000		32
				17,284,202,616	721,798,639	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
03/01/04	06/01/35	03/01/04	06/01/35	-144,400,000		2
						3
04/01/15	04/01/29	04/01/15	04/01/29	-203,460,000		4
						5
09/21/10	0901/29	09/21/10	09/01/29	-100,000,000		6
						7
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	-616,900,000		8
						9
						10
04/01/99	04/01/29	04/01/99	04/01/29	300,000,000	19,950,000	11
						12
09/01/03	09/01/53	09/01/03	09/01/53	6,345,473	323,134	13
						14
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx		-1,785,089	15
						16
				306,345,473	18,488,045	17
						18
					-2	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				17,284,202,616	721,798,639	33

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

Maturities and sinking fund requirements of long-term debt for the five years subsequent to December 31, 2020 will be: $1,029M for 2021; $364M for 2022; $364M for 2022; $900M for 2023; $91M for 2024 and $900M for 2025.

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.

During 2020, respondent capitalized a portion of interest expense on long-term debt for the purpose of financing the company's nuclear fuel inventory. For 2020 the capitalized interest related to nuclear fuel totaled $1,785,089.

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

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.

Schedule Page: 256.1 Line No.: 23 Column: a

08-10-014 - In October 2008, the company received authority from the California Public Utilities Commission to issue $2,000,000,000 of new debt under Decision 08-10-014. In April 2020, the company issued 3.70% First Mortgage bond series 2018E Reopener for an additional $600,000,000 due 2025. At December 2020 total remaining authority for new debt was $1,400,000,000.

Schedule Page: 256.1 Line No.: 30 Column: a

16-02-018 - In February 2016, the company received authority from the California Public Utilities Commission to issue $3,375,000,000 of new debt under Decision 16-02-018. In January 2020, the company issued 2.85% First Mortgage bond series 2019C Reopener for an additional $100,000,000 due 2029. At December 2020 there is no remaining authority for new debt.

Schedule Page: 256.2 Line No.: 1 Column: a

16-02-018 and 18-06-008 – In February 2016 and June 2018, the company received authority from the California Public Utilities Commission to issue $3,375,000,000 of new debt under Decision 16-02-018 and $2,955,000,000 of new debt under Decision 18-06-008. In January 2020 and March 2020, the company issued 3.65% First Mortgage bond series 2020A and 2020A Reopener for an additional $500,000,000 and $700,000,000, respectively, due 2050. At December 2020, there is no remaining authority for new debt under 16-02-018 and under 18-06-008 was $50,100,000.

Schedule Page: 256.2 Line No.: 4 Column: a

16-02-018 – In February 2016, the company received authority from the California Public Utilities Commission to issue $3,375,000,000 of new debt under Decision 16-02-018. In March 2020, the company issued 2.25% First Mortgage bond series 2020B Reopener for an additional $400,000,000 due 2030. At December 2020 there is no remaining authority for new debt.

Schedule Page: 256.2 Line No.: 6 Column: a

20-04-016 - In April 2020, the company received authority from the California Public Utilities Commission to issue $7,125,000,000 of new debt under Decision 20-04-016. In October 2020, the company issued 1.20% First Mortgage bond series 2020C $350,000,000 due 2026. At December 2020 total remaining authority for new debt was $6,775,000,000.

Schedule Page: 256.2 Line No.: 11 Column: a

Bonds subject to mandatory repurchase at April 1, 2020.

Schedule Page: 256.2 Line No.: 13 Column: a

Bonds subject to mandatory repurchase at December 1, 2023.

Schedule Page: 256.2 Line No.: 15 Column: a

Bonds subject to mandatory repurchase at April 1, 2020.

Schedule Page: 256.2 Line No.: 17 Column: a

Bonds subject to mandatory repurchase at April 1, 2020.

Schedule Page: 256.2 Line No.: 21 Column: a

Bonds subject to mandatory repurchase at April 1, 2020.

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	04/14/2021	End of 2020/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)	942,385,439
2		
3		
4	Taxable Income Not Reported on Books	
5		458,793,040
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		3,177,063,937
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-405,824,493
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-5,719,533,535
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-1,547,115,611
28	Show Computation of Tax:	
29	Federal Tax @ 21%	-324,894,278
30		
31		
32	Alternative Minimum Tax	
33	Reduction of 2017 172(f) C/B due to haircut in credit	12,303,625
34	FIN 48 Adjustments	-704,079
35	Return to Provision Adjustment	-53,802
36	NOL Reclass	324,894,278
37		
38		
39		
40	Total Federal Income Tax Expense/(Benefit) Accrual	11,545,744
41		
42		
43		
44		

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

Book Income/(loss) - Pre Tax	665,487,301
CA State tax expense	(81,836,566)
Federal Tax Expense	(195,061,571)
Net income/(loss) per FERC Form 1 (pg. 117 - Col C, Line 78)	942,385,439

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

Taxable Income Not Recorded on Books
M1 (Line 1)

CIAC/ITCC	132,342,397
Temporary - Others	105,556,054
Decommissioning	220,896,989
CCFT Lag - Electric Current Year	(2,400)
	458,793,040

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

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

Book Depreciation	2,064,386,651
Pension and PBOPs	(6,257,781)
Federal Tax Expense	(195,061,571)
CA State tax expense	(81,836,566)
Permanent - Others	42,360,996
Temporary - Others	325,492,478
Wildfire Reserve	1,027,979,733
	3,177,063,937

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

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

AFUDC Equity/Debt	173,988,058
Book Gain/(Loss)	191,656,097
Permanent - Others	40,180,337
	405,824,493

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

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

Tax Depreciation	1,453,250,077
Tax Gain/(Loss)	18,040,511
Repairs Deduction	1,040,783,680
Removal Costs	826,901,005
Capitalized Software labor	206,965,974
Mixed Service Cost	185,973,584

Decommissioning	223,296,273
Balancing Accounts	1,474,816,884
Audit Rollforwards	222,760
Temporary - Others	239,112,175
Permanent - Others	50,170,612
	5,719,533,535

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	04/14/2021	End of 2020/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	-90,944,238		9,975,426	21,948,212	-10,029,228
4	Tax Reserve - Regulatory	-25,558,343				25,558,343
5	Income Taxes	116,502,581				-47,452,753
6	Fed Ins Cont Act- Current	1,772,498		125,881,899	-68,748,034	37,853
7	FICA/OASDI Emp Incntv	9,323,259		-1,579,284		
8	FICA/HIT Emp Incntv	2,261,190		347,819		
9	Fed Unemp Tax Act-Current	152,134		594,377	-598,995	-137,739
10						
11	SUBTOTAL- FED TAXES :	13,509,081		135,220,237	-47,398,817	-32,023,524
12						
13	STATE TAXES :					
14						
15	CA Corp. Franchise Tax	-31,487,869		-12,556,340	20,995,200	23,031,147
16	Income Tax- Arizona	-252,719				
17	Income Tax- New Mexico	-500			-200	
18	Income Tax- UT & CO					
19	Income Tax- DC	-6,519				
20	Accr Tax FIN48staST					
21	Ppd Inc Tax(Income	31,747,605				-31,469,806
22						
23						
24	CA SUI Current	144,381		5,929,800	-5,978,100	
25	SUI TAX - NEVADA	-51		2,408	-2,357	
26	ACCD SUI TAX - WASH D.C.	-932		162	-1,973	2,743
27	D.C. SUI TAX -EME	99				-99
28	SF Pyrl Exp Tx - SCE	-44,986		97,096	-69,258	17,258
29	CADI Vol Plan Assess	597,176		2,012,111	-2,346,956	2,766
30	Use Tax-California-Current	112,329		274,661	-285,700	
31	Accrued District/Local use CA	19,581		37,178	-39,196	
32	SALES TAX ACCRUED					
33	SALES TAX ACCRUED	22,639,542		83,969,303	-76,990,733	
34	Sales Tax Payable - CA	16,666		-487	341	
35	Sales Tax Payable - District					
36	Other Taxes Payable Contra					
37	Sales Tax Accrued/Contra					
38	ROUNDING ADJUSTMENT					
39	SUBTOTAL-STATE TAXES:	23,483,803		79,765,892	-64,718,932	-8,415,991
40						
41	TOTAL	36,992,884	-13,316,679	609,087,229	-511,529,075	-40,439,515

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	LOCAL TAXES:					
2						
3	Property Tax-Ariz Current			5,725,436	-7,710,680	1,985,243
4	Property Tax-Ariz Prepaid		-2,596	1,986,509		-1,985,243
5	Property Tax-Calif Current			287,762,529	-389,740,049	101,977,520
6	Property Tax-Calif Prepaid		-12,789,308	96,630,197	117,885	-101,977,520
7	Property Tax-D.C. Current					
8	Property Tax-Nevada Current			257,678	-2,125,690	1,868,012
9	Property Tax-Nevada Prepaid		-524,775	1,738,751	47,208	-1,868,012
10	Property Tax-N Mex Current					
11	Property Tax-N Mex Prepaid					
12						
13	SUBTOTAL- LOCAL TAXES		-13,316,679	394,101,100	-399,411,326	
14						
15						
16						
17						
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22						
23						
24						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	36,992,884	-13,316,679	609,087,229	-511,529,075	-40,439,515

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
-69,049,828		-3,465,608			13,441,034	3
						4
69,049,828						5
58,944,216		125,500,351			381,548	6
7,743,975		-1,579,284				7
2,609,009		347,819				8
9,777		592,590			1,787	9
						10
69,306,977		121,395,868			13,824,369	11
						12
						13
						14
-17,862		-17,348,338			4,791,998	15
-252,719						16
-700						17
						18
-6,519						19
						20
277,799						21
						22
						23
96,081		5,912,271			17,529	24
		2,408				25
		152			10	26
						27
110		97,096				28
265,097		2,012,111				29
101,290					274,661	30
17,563					37,178	31
						32
29,618,112					83,969,303	33
16,520					-487	34
						35
						36
						37
1						38
30,114,773		-9,324,300			89,090,192	39
						40
99,421,750	-18,626,904	476,086,628			133,000,601	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	04/14/2021	End of 2020/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
		5,721,752			3,684	3
	-1,330	1,984,943			1,566	4
		265,795,707			21,966,822	5
	-18,018,746	89,036,237			7,593,960	6
						7
		190,430			67,248	8
	-606,828	1,285,991			452,760	9
						10
						11
						12
	-18,626,904	364,015,060			30,086,040	13
						14
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						39
						40
99,421,750	-18,626,904	476,086,628			133,000,601	41

Schedule Page: 262 Line No.: 3 Column: f
Includes all charges that are recorded to long term payable, FERC Account 253.

Schedule Page: 262 Line No.: 4 Column: f
Reclass to long term payable, FERC Account 253.

Schedule Page: 262 Line No.: 5 Column: f
Reclass expected tax refunds to FERC Account 143.

Schedule Page: 262 Line No.: 6 Column: f
Mainly due to payroll tax true-up.

Schedule Page: 262 Line No.: 9 Column: f
Mainly due to payroll tax true-up.

Schedule Page: 262 Line No.: 15 Column: f
Includes all charges that are recorded to long term payable, FERC Account 253.

Schedule Page: 262 Line No.: 21 Column: f
Reclass expected tax refunds to FERC Account 143.

Schedule Page: 262 Line No.: 26 Column: f
Mainly due to payroll tax true-up.

Schedule Page: 262 Line No.: 27 Column: f
Mainly due to payroll tax true-up.

Schedule Page: 262 Line No.: 28 Column: f
Mainly due to payroll tax true-up.

Schedule Page: 262 Line No.: 29 Column: f
Mainly due to payroll tax true-up.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		66,459,419	410/411		410/411	5,088,500	
8	TOTAL	66,459,419				5,088,500	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
61,370,919	-13		7
61,370,919			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
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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	04/14/2021	End of 2020/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	878,888	Various	28,565	5,084	855,407
2						
3	Accrued Tax Liabilities - LT	86,599,122	Various	70,168,515	32,190,520	48,621,127
4						
5	Miscellaneous Work In Progress	478,628,202	Various	5,317,625,280	5,324,128,519	485,131,441
6						
7	Derivative Conversion - LT	404,990,003	Various	171,122,857	5,480,078	239,347,224
8	(Amort. Period: 12/2006-5/2026)					
9						
10	Income Tax Component of	242,690,197	Various	287,103,800	292,335,863	247,922,260
11	Contributions in Aid of					
12	Construction					
13						
14	SDG&E Liability - LT	47,218,980	Various	38,698,466	3,816,781	12,337,295
15						
16	Misc LT Liabilities	3,959,128	Various	3,754,598	4,071,368	4,275,898
17						
18	Environmental Remediation	242,205,399	Various	24,694,100	41,497,926	259,009,225
19						
20	TDBU Collateral	25,792,169	Various	8,390,981	1,763,384	19,164,572
21						
22	Deferred Revenue	39,019,516	Various	3,353,919		35,665,597
23						
24	QF - ERR Development Costs	87,299,359	Various	75,280	2,221,000	89,445,079
25						
26	Miscellaneous:					
27	Deferred Credits	66,953,822	Various	1,020,599,810	1,019,562,711	65,916,723
28						
29	Intercompany Executive Compen-	72,773,692	Various	22,853,947	17,886,668	67,806,413
30	sation Plan					
31						
32	CSBU Long-Term Customer	3,950,159	Various	1,835,782	7,102,442	9,216,819
33	Deposit					
34						
35	COSO Contract Termination Fee	28,812,500	232	28,812,500		
36						
37	Wildfire Insurance Fund - LT	785,316,622	Various	92,041,142	10,195,647	703,471,127
38						
39	Decarbonization LT Liability		Various	42,377,404	117,397,961	75,020,557
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	2,617,087,758		7,133,536,946	6,879,655,952	2,363,206,764

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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

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
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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	04/14/2021	End of 2020/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	8,046,241,066	1,882,892,077	1,775,946,110
3	Gas	919,589	193,839	242,549
4	Other	4,811,958		
5	TOTAL (Enter Total of lines 2 thru 4)	8,051,972,613	1,883,085,916	1,776,188,659
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	8,051,972,613	1,883,085,916	1,776,188,659
10	Classification of TOTAL			
11	Federal Income Tax	8,051,972,613	1,883,085,916	1,776,188,659
12	State Income Tax			
13	Local Income Tax			

NOTES

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
			714,235,606		1,226,120,490	8,665,071,917	2
			29,697		25,450	866,632	3
27,005,062	15,903,620		10,618,719		125,181	5,419,862	4
27,005,062	15,903,620		724,884,022		1,226,271,121	8,671,358,411	5
							6
							7
							8
27,005,062	15,903,620		724,884,022		1,226,271,121	8,671,358,411	9
							10
27,005,062	15,903,620		724,884,022		1,226,271,121	8,671,358,411	11
							12
							13

NOTES (Continued)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
282	Fully Normalized Deferred Tax	(1,188,810,901)	(1,214,609,194)
282	Property/Non-ISO	(6,775,581,015)	(7,324,771,034)
282	Capitalized Software	(81,849,150)	(125,691,689)
	Total Electric	(8,046,241,066)	(8,665,071,917)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS AND OTHER INCOME:			
282	Property/Non-ISO	(919,589)	(866,632)
	Total Gas	(919,589)	(866,632)

Schedule Page: 274 Line No.: 4 Column: k

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER:			
282	Property/Non-ISO	(4,811,958)	(5,419,862)
	Total Other	(4,811,958)	(5,419,862)

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Detail Attached	800,274,001	1,372,182,545	594,849,843
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	800,274,001	1,372,182,545	594,849,843
10	Gas			
11	See Detail Attached	17,512	294,987	182,329
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	17,512	294,987	182,329
18	TOTAL Other (See Detail Attach	654,218		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	800,945,731	1,372,477,532	595,032,172
20	Classification of TOTAL			
21	Federal Income Tax	800,945,731	1,372,477,532	595,032,172
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	04/14/2021	End of 2020/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		Various	2,657,129	Various	529,103,409	2,104,052,983	3
							4
							5
							6
							7
							8
			2,657,129		529,103,409	2,104,052,983	9
							10
		Various	820	Various	3,849	133,199	11
							12
							13
							14
							15
							16
			820		3,849	133,199	17
1,317,456	2,555,946	Various	-1,611,654	Various	5,399	1,032,781	18
1,317,456	2,555,946		1,046,295		529,112,657	2,105,218,963	19
							20
1,317,456	2,555,946		1,046,295		529,112,657	2,105,218,963	21
							22
							23

NOTES (Continued)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
283	Ad Valorem Lien Date Adj - Electric	(50,569,342)	(60,649,530)
283	Ad Val Lien Date Adj - Elect - FERC	(8,664,108)	(10,321,989)
283	Refunding & Retirement of Debt	(33,097,558)	(30,768,479)
283	Health Care - IBNR	(1,593,695)	(1,380,206)
283	Balancing Accounts	(567,470,431)	(1,107,676,776)
283	Decommissioning	(449,253,650)	(515,023,097)
283	Regulatory Assets/Liab	57,886,963	-
283	Temp-Other/Non-ISO	252,487,820	(378,232,906)
	Total Electric	(800,274,001)	(2,104,052,983)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS AND OTHER INCOME:			
283	Temp - Other/Non-ISO	(17,512)	(133,198)
	Total Gas	(17,512)	(133,198)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER:			
283	Temp - Other/Non-ISO	(654,218)	(1,032,782)
	Total Other	(654,218)	(1,032,782)

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	04/14/2021	End of 2020/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	Demand Reduction and Self-Generation Program	297,644,542	407	39,384,761	58,122,941	316,382,722
2	To track the recorded incremental program costs					
3	and requirement recorded in the Base Revenue					
4	requirement Balancing Account (BRRBA) associated					
5	with SCE's Small Commercial Demand responsiveness					
6	Pilot Program and the Self-Generation Pilot					
7	Program authorized by the CPUC D.01-03-073.					
8						
9	Energy Savings Assistance Program (Formerly Low	95,449,386	407	57,130,368	66,501,589	104,820,607
10	Income Program Adjustment Mechanism)					
11	To track the Public Purpose Program Charge Funds					
12	allocable to the 1998 low income programs and the					
13	1998 low income energy efficiency program					
14	expenses. Resolution E-3894.					
15						
16	Electric Deferred Refund Account	7,734,149	254	7,755,303	7,943,034	7,921,880
17	To record credits for electric disallowances					
18	ordered by the Commission, Utility Electric					
19	Generation (UEG) shares of gas disallowances					
20	ordered by the Commission or FERC and electric					
21	and UEG amounts resulting from the settlement of					
22	reasonableness disputes at the Commission or					
23	FERC. D.05-03-022.					
24						
25	Procurement Energy Efficiency Balancing Acct.	240,357,080	407	202,093,566	117,379,481	155,642,995
26	To track the difference between actual incremen-					
27	tal procurement-related energy efficiency costs					
28	and authorized procurement-related energy					
29	efficiency revenues per D.03-12-062.					
30						
31	Asset Retirement Obligation (ARO)	1,569,687,643	Various	1,071,468,915	1,438,588,027	1,936,806,755
32	To establish a regulatory liability for					
33	decommissioning costs collected in rates					
34	for ARO assets.					
35						
36	Energy Resource Recovery Account	22,623,698	Various	561,287,884	686,664,450	148,000,264
37	To record SCE's ERRA Revenue, Utility Retained					
38	Generation fuel costs, and purchased power					
39	related expenses, pursuant to D.02-10-062.					
40						
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Miscellaneous Regulatory Liability	44,232,751	Various	277,817,404	239,042,179	5,457,526
3	To capture various accrued purchased power					
4	agreements D.07-03-005 and other					
5	miscellaneous regulatory liabilities.					
6						
7	Demand Response Program Balancing Account (DRPBA)	70,578,678	Various	138,505,009	163,994,643	96,068,312
8	To record the difference between the actual					
9	capital related revenue requirement and O&M costs					
10	incurred by SCE and the authorized Demand					
11	Response Revenue Requirement approved by the					
12	Commission in D.06-03-024 and in SCE's					
13	General Rate Case (GRC) proceedings					
14	D.14-10-036.					
15						
16	California Solar Inititative Program	103,980,436	407	9,079,742	2,687,981	97,588,675
17	Balancing Account					
18	To track the recorded incremental California					
19	Solar Initiative Program costs and authorized					
20	distribution revenue requirement recorded in the					
21	Base Revenue Requirement Balancing Account					
22	(BRRBA) associated with SCE's California					
23	Solar Initiative Program, pursuant to D.06-01-024					
24						
25	Post Employment Benefits Other than Pensions		407	25,075,118	30,039,810	4,964,692
26	(PBOP) Costs Balancing Account					
27	To record the difference between PBOP costs					
28	authorized by the Commission, and recorded					
29	PBOP expenses, pursuant to D.06-05-016.					
30						
31	WECC Statutory Costs	1	407	3,312,262	6,315,954	3,003,693
32	To record WECC statutory fees being amortized					
33	over 12-month period.					
34						
35	Energy Efficiency Finance Programs Balancing Acct	88,729,477	Various	698,838	4,976,741	93,007,380
36	(OBFBA Previously)					
37	To record the difference between actual and					
38	authorized revenue for OBF loan funding, EE Fin-					
39	ance Pilots and ARRA program credit enhancements					
40	in accordance with D.14-10-046.					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/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						
2	Medical Balancing Account	(1)	Various	32,066,306	36,950,078	4,883,771
3	To record the difference between the authorized					
4	and recorded Medical, Dental, Vision expenses in					
5	accordance with D. 09-03-025.					
6						
7	Misc. On-Bill Financing Regulatory Liability	31,016,966	407	4,350,717	698,838	27,365,087
8	To offset 2010-2012 and 2013-2014 OBF loans					
9	and loan repayments, pursuant to D.14-10-046.					
10						
11	REC Regulatory Liability	9,137,642	407	688,434		8,449,208
12	To record renewable energy credit inventory					
13	as regulatory liability.					
14						
15	Gross Revenue Sharing Mechanism	(2)	254	7,921,879	7,921,881	
16	To record the customers' share of certain Other					
17	Operating Revenue (OOR), D.99-09-070.					
18						
19	Electric Program Investment Charge-CEC, SCE	151,108,822	Various	75,405,251	84,351,888	160,055,459
20	and CPUC					
21	To record authorized administrative and program					
22	EPIC revenue requirements and related program					
23	SCE expenses and authorized program payments					
24	to CEC and CPUC per advice letter 2747-E					
25	dated June 25, 2012.					
26						
27	CARE Balancing Account	15,013,806	Various	48,411,075	33,397,269	
28	To reflect in rates, through application of the					
29	Public Purpose Program Charge the costs					
30	associated with the CARE Program as					
31	authorized in various CPUC Decisions,					
32	D.14-08-030.					
33						
34	GHG Revenue Balancing Account	12,355,404	Various	117,926,865	105,571,461	
35	To record the difference between the amount of					
36	GHG revenue actually returned to customers via					
37	rates and bill credits and the actual amount of					
38	GHG revenue SCE receives through consigning					
39	allowances to the cap and trade auction,					
40	pursuant to D.02-10-062.					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/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						
2	Statewide ME&O Balancing Account	2,348,003	Various	20,064,690	23,660,839	5,944,152
3	To record the difference between Commission-					
4	authorized Statewide Marketing, Education &					
5	Outreach funding and recorded expenses.					
6						
7	Base Revenue Balancing Account	328,599,983	Various	2,245,700,280	1,917,100,297	
8	To record the difference between the commission					
9	authorized base distribution and generation					
10	revenues, pursant to D.04-07-022 (excluding					
11	Z-factor).					
12						
13	Mohave SO2 Allowance Revolving Fund Memo Account	3,813,624			26,582	3,840,206
14	To record the net proceeds from the sale of					
15	sulfurdioxide (SO2) emission allowances					
16	rendered surplus by the closure of the Mohave					
17	Generating Station and to maintain and account					
18	for the revolving fund from the sale and use of					
19	these emission credits, pursuant to					
20	D.13-02-004.					
21						
22	Nuclear Decommissioning Adjustment Mechanism	43,682,812	407	34,893,389	36,614,399	45,403,822
23	To record NDAM revenue, authorized and					
24	recorded costs related to the decommissioning of					
25	San Onofre Nuclear Generating Station and Palo					
26	Verde Nuclear Generating Station, pursuant to					
27	D.03-10-015.					
28						
29	New System Gen Balancing Account	188,778	Various	151,613,569	161,697,991	10,273,200
30	To record the benefits and costs of Power Purchae					
31	agreements (PPAs) and SCE owned peaker generation					
32	unit associated with new generation resources,					
33	pursuant to D.06-07-029.					
34						
35	Tax Accounting Memo Account (TAMA)	(1)	182	131,013,353	173,085,845	42,072,491
36	To track impact on authorized CPUC juris-					
37	dictional revenue requirement as adopted in					
38	D.15-11-021; resulting from income tax accounting					
39	method changes, changes in federal or state law					
40	difference between authorized and recorded					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/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	federal and California non-pole loading net					
2	repair deductions, audit findings, or changes					
3	in authorized revenue requirements.					
4						
5	Low Carbon Fuel Standard Revenue Balancing	184,109,294	232	101,350,770	93,689,047	176,447,571
6	Account					
7	To record the revenue from the sale of LCFS					
8	credits and set forth the methodology for the					
9	amount of LCFS credit revenue to be returned to					
10	elgible customers pursuant to Decisions (D.)					
11	14-05-021, 14-07-003 and 14-12-083.					
12						
13	Department of Energy Litigation Memorandum	35,337,387	Various	35,890,354	552,967	
14	Account					
15	To record: (1) SCE's incremental litigation-relad					
16	costs; and (2) proceeds received by SCE from					
17	the federal government for breaching certain					
18	Standard Contracts between SCE and DOE for DOE to					
19	dispose of San Onofre Nuclear Generating					
20	Station (SONGS) spent nuclear fuel.					
21						
22	Green Tariff Shared Renewables Balancing Account		182	6,053	30,598	24,545
23	To record the difference between the actual revee					
24	requirements, based on recorded GRSR commodity-					
25	related costs, and the revenues collected from					
26	indiviudal customers electing to participate in e					
27	GRST Program through charges set to collect					
28	these costs.The revenues collected will be based					
29	on a dollar per kWh charged for each kWh of ener					
30	delivered per a customer's GTSR Program					
31	subscription, pursuant to D.15-01-051.					
32						
33	Aliso Canyon Demand Response Program Balancing	2,331,447	Various	2,983,937	652,490	
34	Account					
35	To record the difference between the actual costs					
36	incurred by SCE for demand response program					
37	activities to help mitigate a natural gas leak at					
38	the Aliso Canyon Natural Gas Storage Facility					
39	(Aliso Canyon) and the authorized Aliso Canyon					
40	Demand Response funding level approved by the					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Commission, D.16-06-029.					
2						
3	Pension Costs Balancing Account	673,957	Various	75,117,780	88,546,322	14,102,499
4	To record the difference between pension					
5	costs authorized by the Commission, and					
6	recorded pension expenses, D.06-05-016.					
7						
8	Results Sharing Memorandum Account (RSMA)		Various	21,653,233	21,751,844	98,611
9	To track the difference between authorized and					
10	recorded Results Sharing expenses paid out,					
11	pursuant to D.06-05-016.					
12						
13	New Solar Home Partnership Program Balancing Acct	48,316,804			336,785	48,653,589
14	To provide funding for financial incentives for					
15	homeowners, builders, and developers to install					
16	solar energy systems on new, energy efficient					
17	residential dwellings. To record the difference					
18	between the aurthorized Program funding and					
19	disbursements of those funds to the CEC or					
20	applicants, pursuant to D.16-06-006.					
21						
22	Bilateral Energy & Gas Financial Instruments	86,617,162	Various	205,911,062	223,353,441	104,059,541
23	To record the mark-to-market adjustments					
24	related to the financial instruments used to					
25	hedge power purchases and natural gas costs					
26	for utility owned generators.					
27						
28	FERC Formula Rate	280,279,854	Various	356,436,399	142,794,009	66,637,464
29	To record the difference between billed and un-					
30	billed revenue and the recorded transmission					
31	revenue requirement to cover the costs of owning					
32	and operating transmission facilities under ISO					
33	control, per FERC Formula Rate Protocols					
34	ER11-3697.					
35						
36	CPUC Excess Deferred Taxes & Gross-Up TCAJA	2,422,697,729	Various	167,098,251		2,255,599,478
37	To record the CPUC-related difference in					
38	accumulated deferred tax balances as a result					
39	of the reduction of the federal income tax rate					
40	by the Tax Cuts And Job Acts to 21% from the					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	previous 35% and the related tax gross-up that					
2	will be refunded to customers. Excess deferred					
3	taxes subject to the tax normalization require-					
4	ments will be refunded to ratepayers over the					
5	life of the underlying liability that gave rise					
6	to the deferred taxes.					
7						
8	FERC Excess Deferred Taxes-TCAJA	637,169,884	Various	27,521,078		609,648,806
9	To record the FERC-related difference in accumu-					
10	lated deferred tax balances as a result of the					
11	reduction of the federal income tax rate by the					
12	Tax Cuts And Jobs Act to 21% from the previous					
13	35% that will be refunded to customers. Excess					
14	deferred taxes subject to the tax normalization					
15	requirements will be refunded over the life of					
16	the underlying liability that gave rise to the					
17	deferred taxes.					
18						
19	FERC Excess Deferred Tax Gross-Up-TCAJA	247,586,760	Various	10,693,938		236,892,822
20	To record the FERC-related tax gross-up on the					
21	difference in accumulated deferred tax balances					
22	as a result of the reduction of the federal in-					
23	come tax rate by the Tax Cuts And Jobs Act to					
24	21% from the previous 35% that will be					
25	refunded to customers.					
26						
27	PBOP Reg. Liability Net of Regulatory Adjustments	416,101,000	128	30,162,000	284,706,000	670,645,000
28	To reflect regulatory liability resulting from					
29	the adoption of SFAS 158 Employer's Accounting					
30	for Defined Benefit Pension & Other Post					
31	retirement Plan (D.06-05-016), net of difference					
32	between PBOP expense recorded for US GAAP					
33	versus PBOP expense recorded for Utility					
34	expense.					
35						
36	Solar on Multifamily Affordable Housing Program	86,171,782	407	5,628,889	76,515,119	157,058,012
37	(SOMAH) Balancing Account (SOMAHBA)					
38	To record the difference between the authorized					
39	SOMAH Program funding levels and all incre-					
40	mental costs associated witht he SOMAH Program,					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	including costs of conducting a Request for					
2	Approval (RFP), contributions to Program Admin-					
3	istrator (PA) administrative budgets, utility					
4	administration costs and incentive payments					
5	pursuant to Decision (D.)17-12-022.					
6						
7	Public Purpose Programs Adjustments Mechanism	31,883,321	Various	314,792,146	282,908,825	
8	To record Public Goods Charge Revenue, PGC ex-					
9	penses authorized in P.U. Code Section 399.8,					
10	and other CPUC Public Purpose Program revenues					
11	and expenses (D.11-12-038). Programs include:					
12	ESAP, CARE, EPIC, OBF, PEEBA, LCRPBA, & NSHF.					
13						
14	Disadvantaged Communities Singlefamily	3,874,670	407	3,126,128	5,056,366	5,804,908
15	Solar Homes Balancing Account					
16	To record the difference between SCE's proport-					
17	ionate share of the $10 million per year DAC-SASH					
18	budget starting in 2019 and the actual costs rel-					
19	ated to the operation of the DACSASH program,					
20	as authorized in Ordering Paragraph 8 of D.18-06-					
21	027.					
22						
23	Pole Loading and Deteriorated Pole Balancing		Various	195,252,794	195,252,794	
24	Account (PLDPBA)					
25	To record the difference between recorded capital					
26	related revenue, operating expenses, and the					
27	authorized revenue requirement authorized by					
28	D.15-11-021.					
29						
30	Reliability Service Balancing Account	1,016,356	Various	329,820	66,463,609	67,150,145
31	To track the RS revenues and RS costs to					
32	ensure that SCE neither over-collects nor under-					
33	collects RS costs assessed (D.06-05-016).					
34						
35	Affiliate Transfer Memorandum Account	22,387	254	22,388	97,494	97,493
36	To record the transfer fees received from aff-					
37	iliates when an employee is transferred, assigned					
38	or otherwise employed by the affiliate.					
39						
40						
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Catastrophic Event Memorandum Account -		Various	1,298,895	1,298,895	
3	2017 Fires					
4	To record costs incurred by SCE associated with a					
5	catastrophic event for restoring utility service					
6	customers; repairing, replacing, or restoring					
7	damaged utility facilities; and complying with					
8	governmental agency orders.					
9						
10	San Joaquin Valley Disadvantaged Communities	3,865,343	407	941,803	10,199,214	13,122,754
11	Pilot Balancing Account					
12	To record the difference between the Commission-					
13	authorized pilot project funding and the recorded					
14	non-leveraged costs of the pilot projects over a					
15	period of 3 years.					
16						
17	Water Revenue Adjustment Mechanism/Modified		Various	3,919,733	4,123,836	204,103
18	Cost Balancing Account (WRAM/MCBA)					
19	To record the difference between SCE's authorized					
20	sales revenue and actual recorded revenue col-					
21	lected through sales and the difference between					
22	authorized variable production expense and the					
23	actual variable production expense incurred.					
24						
25	Clean Energy Optimization Pilot Balancing Account		Various	5,124,845	10,067,916	4,943,071
26	To record the difference between CEOP					
27	project costs, including CEOP					
28	performance payments and administrative costs,					
29	and the funds transferred from the					
30	Green House Gas Revenue Balancing Account					
31	(GHGRBA), as authorized in Decision (D.)19-04-01.					
32						
33	Community Solar Green Tariff Balancing Account		Various	237,267	2,302,703	2,065,436
34	To record the difference between 1) the costs					
35	related to the implementation and operation of					
36	the Disadvantaged Communities-Green Tariff					
37	(CSGT) program, and 2) the funding available					
38	through GHG allowance revenues and/or a transfer					
39	to the Public Purpose Programs charge, as author-					
40	ized in D.18-06-027 and modified by Resolution					
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/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	E-4999.					
2						
3	Disadvantaged Communities Green Tariff Balancing		Various	267,623	2,300,135	2,032,512
4	Account					
5	To record the difference between 1) the					
6	costs related to the implementation and operation					
7	of the Disadvantaged Communities-Green Tariff					
8	(DACGT) program, and 2) the funding available					
9	through GHG allowance revenues and/or a transfer					
10	to the Public Purpose Programs charge, as					
11	authorized in D.18-06-027 and modified by					
12	Resolution E-4999.					
13						
14	GCAC Regulatory Liability Balancing Account		Various	119,568	316,100	196,532
15	Balance composed of Gas Cost Adjustment Clause					
16	which recovers/refunds gas costs on Catalina					
17	Island (D.82-04-010).					
18						
19	Wheeler North Reef Expansion Project Memorandum		182	87,405	87,405	
20	Account					
21	To track costs associated with the WNR Expansion					
22	Project pursuant to the Administrative Law Judges					
23	Ruling Granting SCE's motion to establish					
24	a Memorandum Account. Application A. 16-12-002.					
25						
26	Power Charge Indifference Adjustment Under-		Various	3,502,784	3,502,784	
27	collection Balancing Account					
28	To record any shortfall (and any associated					
29	repayment) in billed revenues accruing from					
30	departing load customers and the corresponding					
31	financing of the revenue shortfall by bundled					
32	service customers due to the implementation					
33	of PCIA Rate Caps.					
34						
35	ERRA and CPPMA Related Unamortized Debt Fees		407	1,873,425	3,122,375	1,248,950
36	To record amortization & provision of Debt					
37	Issuance Costs.					
38						
39						
40						
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	Transmission Rev Balancing Acct Adjustment		Various	9,092,183	22,534,060	13,441,877
3	To record transmission revenue credits,					
4	congestion revenue, wheeling revenue, sale					
5	of an FTR revenue, and ancillary service expense					
6	to the TRBAA. Authorized by ER18-154-000.					
7						
8						
9	Rounding Adjustment	(2)			2	
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
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23						
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27						
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29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	7,626,338,812		6,844,107,529	6,945,897,333	7,728,128,616

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	04/14/2021	End of 2020/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	5,383,743,868	4,541,130,693
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	5,486,807,110	5,457,523,526
5	Large (or Ind.) (See Instr. 4)	694,735,604	686,907,701
6	(444) Public Street and Highway Lighting	96,616,470	94,928,630
7	(445) Other Sales to Public Authorities	-32,869	3,001,503
8	(446) Sales to Railroads and Railways	9,022,117	7,948,477
9	(448) Interdepartmental Sales	269,145	258,122
10	TOTAL Sales to Ultimate Consumers	11,671,161,445	10,791,698,652
11	(447) Sales for Resale	241,764,323	138,311,826
12	TOTAL Sales of Electricity	11,912,925,768	10,930,010,478
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	11,912,925,768	10,930,010,478
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,046,348	16,001,742
17	(451) Miscellaneous Service Revenues	12,098,591	13,363,900
18	(453) Sales of Water and Water Power	1,608,238	
19	(454) Rent from Electric Property	80,970,289	81,870,488
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	583,944,996	575,074,017
22	(456.1) Revenues from Transmission of Electricity of Others	129,913,731	132,871,219
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	814,582,193	819,181,366
27	TOTAL Electric Operating Revenues	12,727,507,961	11,749,191,844

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	04/14/2021	End of 2020/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
32,465,350	29,221,836	4,516,288	4,489,461	2
				3
43,391,335	45,831,047	604,448	602,349	4
7,152,378	7,974,644	29,717	30,078	5
425,393	456,293	17,206	17,289	6
	54,933		1	7
71,269	70,940	133	129	8
1,908	1,965	24	24	9
83,507,633	83,611,658	5,167,816	5,139,331	10
4,185,296	4,658,326	26	12	11
87,692,929	88,269,984	5,167,842	5,139,343	12
				13
87,692,929	88,269,984	5,167,842	5,139,343	14

Line 12, column (b) includes $ 520,990,821 of unbilled revenues.

Line 12, column (d) includes 3,815,798 MWH relating to unbilled revenues

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

FERC account 9451000 - Miscellaneous Service Revenues

Service Reconnection / Connection Charges	(5,904,070.73)
Net Energy Metering Application Fee	(3,946,075.00)
Returned Check Charges	(1,213,295.63)
PUC Reimbursement Fee-Elect	(655,977.21)
Other	(379,172.36)
Total	(12,098,590.93)

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

FERC account 9451000 - Miscellaneous Service Revenues

Miscellaneous Service Revenue	(3,174,294.97)
Service Reconnection / Connection Charges	(7,757,272.20)
Returned Check Charges	(1,559,689.07)
Others	(373,596.50)
PUC Reimbursement Fee-Elect	(499,047.69)
Total	(13,363,900.43)

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

FERC account 9456000 - Other Electric Revenues

GHG Allowance Revenue	(420,965,361.60)
Realized Gain(Loss) LCFS (Low Carbon Fuel Standard) CR (411.8)	(85,924,664.65)
ITCC/CIAC Revenues / Grant Amortization	(27,423,197.53)
Gas Sales	(17,908,772.14)
Interconnection Facilities	(14,809,936.94)
Added Facilities	(7,556,391.80)
CCA Information Fee	(2,638,010.84)
Energy Related Services	(3,253,666.78)
Revenue From Recreation, Fish & Wildlife	(862,022.74)
Other	(2,602,970.65)
Total Other Electric Revenues	(583,944,995.67)

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

FERC account 9456000 - Other Electric Revenues

Gas Sales	(14,926,743.02)
GHG Allowance Revenue	(421,170,201.56)
ITCC/CIAC Revenues / Grant Amortization	(27,065,229.58)
Interconnection Facilities	(16,980,562.94)
Realized Gain(Loss) LCFS (Low Carbon Fuel Standard) CR (411.8)	(82,001,189.65)
Miscellaneous Others	(12,930,090.23)
Total Other Electric Revenues	(575,074,016.98)

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	None.				
2					
3					
4					
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41					
42					
43					
44					
45					
46	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	04/14/2021	End of 2020/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	NOTE: See Footnote for Symbols					
2						
3	ACCOUNT 440					
4	D	12,446,554	2,665,540,764	1,833,994	6,787	0.2142
5	D @	18,268	2,258,406	2,368	7,715	0.1236
6	D $	4,250,631	619,563,105	627,118	6,778	0.1458
7	D-CARE	5,526,285	781,654,297	827,617	6,677	0.1414
8	D-CARE @	3,377	148,215	528	6,396	0.0439
9	D-CARE $	1,561,305	108,740,753	253,975	6,147	0.0696
10	D-CARE-CPP	2	213	1	2,000	0.1065
11	DCARE-E	3,118	516,177	250	12,472	0.1655
12	DCARE-E $	562	49,835	63	8,921	0.0887
13	DCARE-E-N	26	2,453	2	13,000	0.0943
14	D-CARE-N	239,871	19,844,432	23,927	10,025	0.0827
15	D-CARE-N @	30	1,025			0.0342
16	D-CARE-N $	53,781	1,527,021	5,523	9,738	0.0284
17	D-CARE-N2	-199	-31,781	46	-4,326	0.1597
18	D-CARE-N2 $	-40	-3,611	12	-3,333	0.0903
19	D-CARE-SDP	285,558	37,395,121	35,411	8,064	0.1310
20	D-CARE-SDP @	477	14,672	69	6,913	0.0308
21	D-CARE-SDP $	70,325	4,124,382	8,806	7,986	0.0586
22	D-CARE-SDP-N	17,045	1,166,651	1,798	9,480	0.0684
23	D-CARE-SDP-N$	3,826	81,381	409	9,355	0.0213
24	D-CARE-SDP-N2	-23	-2,715	4	-5,750	0.1180
25	D-CARE-SDPN2$	-5	-268	1	-5,000	0.0536
26	D-CARE-SDP-O	12,434	1,739,683	1,522	8,170	0.1399
27	DCARE-SDP-O @	35	1,004	5	7,000	0.0287
28	DCARE-SDP-O $	3,191	215,143	416	7,671	0.0674
29	DCARE-SDP-O-N	763	58,828	80	9,538	0.0771
30	DCARE-SDP-ON$	84	1,471	11	7,636	0.0175
31	DCARE-SDP-ON2	1	1			0.0010
32	DCARE-SDPON2$	-20	-1,105			0.0553
33	D-CPP	4	734			0.1835
34	D-DL #		397			
35	DE	76,599	12,254,471	8,704	8,800	0.1600
36	DE $	11,380	1,003,002	1,370	8,307	0.0881
37	DE-FERA	552	71,696	43	12,837	0.1299
38	DE-FERA $	94	6,119	8	11,750	0.0651
39	DE-FERA-N	15	1,659	1	15,000	0.1106
40	DE-FERA-N $		13			
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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-FERA-SDP	124	15,709	11	11,273	0.1267
3	DE-FERA-SDP $	22	1,248	2	11,000	0.0567
4	DE-FERA-SDP-O	21	2,834	1	21,000	0.1350
5	DE-N	3,862	302,300	396	9,753	0.0783
6	DE-N $	307	6,030	36	8,528	0.0196
7	DE-N2			1		
8	DE-N2 $		3			
9	DE-SDP	15,838	2,363,892	1,729	9,160	0.1493
10	DE-SDP @	13	683	1	13,000	0.0525
11	DE-SDP $	2,007	156,205	222	9,041	0.0778
12	DE-SDP-N	588	39,175	59	9,966	0.0666
13	DE-SDP-N $	49	1,372	5	9,800	0.0280
14	DE-SDP-O	917	144,097	99	9,263	0.1571
15	DE-SDP-O $	125	10,281	14	8,929	0.0822
16	DE-SDP-O-N	9	-113	1	9,000	-0.0126
17	DE-TOU-A	629	88,349	90	6,989	0.1405
18	DE-TOU-A $	69	4,830	12	5,750	0.0700
19	DETOUAFERASDP	5	385	1	5,000	0.0770
20	DE-TOU-A-N	320	11,204	33	9,697	0.0350
21	DE-TOU-A-N $	22	884	2	11,000	0.0402
22	DE-TOU-A-N2	1,079	47,628	131	8,237	0.0441
23	DE-TOU-A-N2 $	87	902	11	7,909	0.0104
24	DE-TOU-A-SDP	291	38,881	35	8,314	0.1336
25	DE-TOU-A-SDP$	25	1,981	3	8,333	0.0792
26	DETOU-A-SDP-N	141	5,622	11	12,818	0.0399
27	DETOU-A-SDPN$	12	47	1	12,000	0.0039
28	DETOU-A-SDPN2	158	2,945	18	8,778	0.0186
29	DETOU-ASDPN2$	9	-23	1	9,000	-0.0026
30	DETOU-A-SDP-O	22	3,235	2	11,000	0.1470
31	DETOUA-SDPON2	8	18	1	8,000	0.0023
32	DE-TOU-B	4,191	613,053	286	14,654	0.1463
33	DE-TOU-B $	479	36,766	32	14,969	0.0768
34	DE-TOUB-FERA$	15	677	1	15,000	0.0451
35	DE-TOU-B-N	109	9,176	7	15,571	0.0842
36	DE-TOU-B-N $	17	264	2	8,500	0.0155
37	DE-TOU-B-N1 $		-66			
38	DE-TOU-B-N2	138	8,026	11	12,545	0.0582
39	DE-TOU-B-N2 $	22	520	2	11,000	0.0236
40	DE-TOU-B-SDP	2,088	289,546	150	13,920	0.1387
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.
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-TOU-B-SDP$	211	14,669	16	13,188	0.0695
3	DETOU-B-SDP-N	27	21	2	13,500	0.0008
4	DETOU-B-SDPN2	113	4,087	10	11,300	0.0362
5	DETOU-B-SDP-O	170	24,727	13	13,077	0.1455
6	DETOU-B-SDPON	9	1,033	1	9,000	0.1148
7	DE-TOUT	318	53,149	22	14,455	0.1671
8	DE-TOUT $	7	579	1	7,000	0.0827
9	DE-TOUT-N	195	11,637	20	9,750	0.0597
10	DE-TOUT-N $	14	2,166	1	14,000	0.1547
11	DE-TOUT-N2	11	939	2	5,500	0.0854
12	DE-TOUT-SDP	230	36,908	16	14,375	0.1605
13	DE-TOUT-SDP $	18	1,254	2	9,000	0.0697
14	DE-TOUT-SDP-N	116	8,479	11	10,545	0.0731
15	DE-TOUT-SDPN$	18	794	1	18,000	0.0441
16	DE-TOUT-SDPON		301	1		
17	DE-TUT SDPON$	4	-1	1	4,000	-0.0003
18	D-FERA	128,136	22,516,956	15,641	8,192	0.1757
19	D-FERA @	52	3,447	8	6,500	0.0663
20	D-FERA $	34,489	3,603,456	4,427	7,791	0.1045
21	D-FERA-N	9,114	887,186	901	10,115	0.0973
22	D-FERA-N $	1,775	51,760	187	9,492	0.0292
23	D-FERA-N2	-15	-2,018	1	-15,000	0.1345
24	D-FERA-N2 $	-1	-84			0.0840
25	D-FERA-SDP	8,581	1,406,828	911	9,419	0.1639
26	D-FERA-SDP @	32	1,144	3	10,667	0.0358
27	D-FERA-SDP $	2,031	180,954	224	9,067	0.0891
28	D-FERA-SDP-N	522	48,306	48	10,875	0.0925
29	D-FERA-SDP-N$	126	4,126	14	9,000	0.0327
30	D-FERA-SDP-O	555	95,409	62	8,952	0.1719
31	D-FERA-SDP-O$	164	17,054	16	10,250	0.1040
32	DFERA-SDP-O-N	18	741	2	9,000	0.0412
33	DFERA-SDP-ON$	4	4			0.0010
34	DM	49,442	10,287,093	3,079	16,058	0.2081
35	DM @	501	40,054	10	50,100	0.0799
36	DM $	30,241	4,145,501	1,679	18,011	0.1371
37	DM-CARE	5	900	1	5,000	0.1800
38	DM-CARE $	6	448	1	6,000	0.0747
39	DM-CARE-E	33	5,255	1	33,000	0.1592
40	DM-N	2,081	290,787	109	19,092	0.1397
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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 440 CONTINUED					
2	DM-N $	1,465	128,094	52	28,173	0.0874
3	DM-N2	2,049	252,505	71	28,859	0.1232
4	DM-N2 $	309	34,102	20	15,450	0.1104
5	DMS-1	27,843	5,177,902	199	139,915	0.1860
6	DMS-1 $	10,020	1,090,452	55	182,182	0.1088
7	DMS-1-N	1,328	77,789	11	120,727	0.0586
8	DMS-1-N $	28	2,355	2	14,000	0.0841
9	DMS-1-N2	3	63			0.0210
10	DMS-2	317,829	51,974,624	887	358,319	0.1635
11	DMS-2 @	876	62,669	5	175,200	0.0715
12	DMS-2 $	83,908	7,414,010	230	364,817	0.0884
13	DMS-2-N	28,564	3,311,516	42	680,095	0.1159
14	DMS-2-N $	5,086	215,294	7	726,571	0.0423
15	DMS-2-N2	21,521	2,174,281	25	860,840	0.1010
16	DMS-2-N2 $		5,597			
17	DMS-2-N2-P $	5,726	603,566	3	1,908,667	0.1054
18	DMS-2-N2-S $	2,229	29,262	4	557,250	0.0131
19	DMS-2-N-P $	444	-2,102	1	444,000	-0.0047
20	DMS-3	10,432	1,971,806	65	160,492	0.1890
21	DMS-3 @	11	1,342			0.1220
22	DMS-3 $	2,583	318,220	6	430,500	0.1232
23	DMS-3-N	1,104	419,896	2	552,000	0.3803
24	DMS-3-P	2,164	373,057	3	721,333	0.1724
25	DMS-3-P $	766	106,853	1	766,000	0.1395
26	DMS-3-P-N	2,672	15,519	2	1,336,000	0.0058
27	DMS-3-P-N2 $	342	43,987			0.1286
28	DMS-3-S-N2	245	21,089	1	245,000	0.0861
29	D-N	1,070,950	108,392,037	113,288	9,453	0.1012
30	D-N @	55	1,898	5	11,000	0.0345
31	D-N $	285,038	16,833,550	28,980	9,836	0.0591
32	D-N2	-1,433	-280,210	245	-5,849	0.1955
33	D-N2 $	-597	-78,269	78	-7,654	0.1311
34	D-PG-S	3	547	1	3,000	0.1823
35	D-SDP	660,397	132,184,224	79,266	8,331	0.2002
36	D-SDP @	2,842	297,692	332	8,560	0.1047
37	D-SDP $	180,326	23,512,686	20,872	8,640	0.1304
38	D-SDP-N	71,928	6,250,079	7,935	9,065	0.0869
39	D-SDP-N @	27	1,430	2	13,500	0.0530
40	D-SDP-N $	18,616	856,247	2,020	9,216	0.0460
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 440 CONTINUED					
2	D-SDP-N2	-50	-7,805	13	-3,846	0.1561
3	D-SDP-N2 $	-25	-2,332	4	-6,250	0.0933
4	D-SDP-O	33,391	6,972,511	4,065	8,214	0.2088
5	D-SDP-O @	112	12,442	15	7,467	0.1111
6	D-SDP-O $	7,988	1,106,440	953	8,382	0.1385
7	D-SDP-O-N	3,874	341,973	449	8,628	0.0883
8	D-SDP-O-N $	720	33,136	84	8,571	0.0460
9	D-SDP-O-N2	-8	-1,502	2	-4,000	0.1878
10	D-SDP-O-N2 $		-33			
11	DTA-CARE-SDP	1,940	239,936	255	7,608	0.1237
12	DTACARE-SDP @	6	53	1	6,000	0.0088
13	DTACARE-SDP $	408	21,631	61	6,689	0.0530
14	DTACARE-SDP-N	1,028	56,616	95	10,821	0.0551
15	DTACARE-SDPN$	303	1,411	27	11,222	0.0047
16	DTACARE-SDPN2	4,892	196,963	568	8,613	0.0403
17	DTACARESDPN2$	948	8,252	108	8,778	0.0087
18	DTACARE-SDP-O	54	7,405	7	7,714	0.1371
19	DTACARE-SDPO$	32	1,753	5	6,400	0.0548
20	DTACARESDPO-N	78	5,872	7	11,143	0.0753
21	DTACARESDPON$	8	151	1	8,000	0.0189
22	DTACARESDPON2	238	11,079	31	7,677	0.0466
23	DTACARSDPON2$	17	80	4	4,250	0.0047
24	DTAFERASDPN1$	11	-36	1	11,000	-0.0033
25	DTAFERA-SDPN2	218	11,582	21	10,381	0.0531
26	DTAFERASDPN2$	49	463	5	9,800	0.0094
27	DTAFERASDPON	6	627	1	6,000	0.1045
28	DTAFERASDPON2	5	56	1	5,000	0.0112
29	DTA-SDP-O-N	572	33,011	60	9,533	0.0577
30	DTA-SDP-O-N $	103	4,701	10	10,300	0.0456
31	DTA-SDP-O-N2	1,144	50,037	135	8,474	0.0437
32	DTA-SDP-O-N2$	228	4,580	27	8,444	0.0201
33	DTB-CARE-SDP	8,641	1,107,656	608	14,212	0.1282
34	DTB-CARE-SDP$	2,497	146,680	166	15,042	0.0587
35	DTBCARE-SDP-N	461	36,146	28	16,464	0.0784
36	DTBCARESDP-N$	89	3,107	5	17,800	0.0349
37	DTBCARE-SDPN2	452	24,299	27	16,741	0.0538
38	DTBCARESDPN2$	32	606	3	10,667	0.0189
39	DTBCARE-SDP-O	242	32,593	17	14,235	0.1347
40	DTBCARE-SDPO$	45	2,878	3	15,000	0.0640
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 440 CONTINUED					
2	DTBCARESDPON1	4	2,141			0.5353
3	DTBCARESDPON2	1	2			0.0020
4	DTB-SDP-O-N	208	23,256	15	13,867	0.1118
5	DTB-SDP-O-N $	35	2,928	3	11,667	0.0837
6	DTB-SDP-O-N2	169	9,174	18	9,389	0.0543
7	DTB-SDP-O-N2$	48	1,884	2	24,000	0.0393
8	D-TOU-1-P	-2	-328			0.1640
9	D-TOU1-P-CARE	-10	-1,433			0.1433
10	D-TOU-2-P		-56			
11	D-TOU-A	70,660	13,267,229	12,933	5,464	0.1878
12	D-TOU-A @	18	2,220	2	9,000	0.1233
13	D-TOU-A $	23,497	2,939,407	4,041	5,815	0.1251
14	D-TOU-A-CARE	20,889	2,635,513	3,949	5,290	0.1262
15	D-TOU-A-CARE$	6,901	412,467	1,322	5,220	0.0598
16	DTOU-A-CARE-N	7,053	417,418	688	10,251	0.0592
17	DTOU-A-CAREN$	1,274	23,196	125	10,192	0.0182
18	DTOU-A-CAREN2	68,648	3,837,269	7,477	9,181	0.0559
19	DTOU-ACAREN2@		-62			
20	DTOU-ACAREN2$	12,558	230,628	1,457	8,619	0.0184
21	D-TOU-A-FERA	432	71,476	67	6,448	0.1655
22	D-TOU-A-FERA$	126	11,655	23	5,478	0.0925
23	D-TOUA-FERA-N	459	32,790	47	9,766	0.0714
24	D-TOUA-FERAN$	48	200	4	12,000	0.0042
25	D-TOUA-FERAN2	2,729	186,077	297	9,189	0.0682
26	D-TOUAFERAN2$	444	16,523	46	9,652	0.0372
27	DTOUAFERASDP	97	14,158	12	8,083	0.1460
28	DTOUAFERASDP$	25	2,001	3	8,333	0.0800
29	DTOUAFERASDPN	53	3,631	4	13,250	0.0685
30	D-TOU-A-N	71,573	4,938,107	7,100	10,081	0.0690
31	D-TOU-A-N @	17	1,115	1	17,000	0.0656
32	D-TOU-A-N $	16,683	518,764	1,609	10,369	0.0311
33	D-TOU-A-N2	360,388	22,614,614	41,115	8,765	0.0628
34	D-TOU-A-N2 @	31	554	4	7,750	0.0179
35	D-TOU-A-N2 $	79,695	2,838,291	8,590	9,278	0.0356
36	D-TOU-A-SDP	10,047	1,724,583	1,493	6,729	0.1717
37	D-TOU-A-SDP @	1	67			0.0670
38	D-TOU-A-SDP $	2,404	261,030	345	6,968	0.1086
39	D-TOU-A-SDP-N	10,401	639,716	1,028	10,118	0.0615
40	D-TOU-A-SDPN$	2,232	67,755	223	10,009	0.0304
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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1	ACCOUNT 440 CONTINUED					
2	D-TOUA-SDP-N2	20,472	897,616	2,354	8,697	0.0438
3	D-TOUA-SDPN2$	4,468	114,374	481	9,289	0.0256
4	D-TOU-A-SDP-O	373	70,897	56	6,661	0.1901
5	D-TOUA-SDP-O$	99	11,698	14	7,071	0.1182
6	D-TOU-B	404,118	75,450,552	23,197	17,421	0.1867
7	D-TOU-B @	114	11,994	9	12,667	0.1052
8	D-TOU-B $	139,621	17,383,275	7,561	18,466	0.1245
9	D-TOU-B-CARE	45,402	5,987,422	2,974	15,266	0.1319
10	D-TOU-B-CARE$	13,763	915,911	892	15,429	0.0665
11	DTOU-B-CARE-N	4,300	401,649	222	19,369	0.0934
12	DTOU-B-CAREN$	785	30,723	44	17,841	0.0391
13	DTOU-B-CAREN2	2,097	120,162	176	11,915	0.0573
14	DTOU-BCAREN2$	615	14,259	35	17,571	0.0232
15	D-TOU-B-FERA	2,317	380,566	151	15,344	0.1642
16	D-TOUB-FERA $	1,077	90,961	55	19,582	0.0845
17	D-TOUB-FERA-N	297	26,233	16	18,563	0.0883
18	D-TOUBFERA-N$	70	952	5	14,000	0.0136
19	D-TOUB-FERAN2	111	3,320	11	10,091	0.0299
20	D-TOUBFERAN2$	39	1,714	4	9,750	0.0439
21	DTOUBFERASDN$	10	124	1	10,000	0.0124
22	DTOUBFERASDN2	30	1,373	3	10,000	0.0458
23	DTOUBFERASDO$	12	1,064	1	12,000	0.0887
24	D-TOUBFERASDP	356	57,363	24	14,833	0.1611
25	DTOUBFERASDP$	105	8,755	8	13,125	0.0834
26	DTOUBFERASDPN	108	10,870	5	21,600	0.1006
27	DTOUBFERASDPO	7	1,270			0.1814
28	DTOUBFERSDN2$	9	143	1	9,000	0.0159
29	D-TOU-B-N	38,114	4,807,996	2,168	17,580	0.1261
30	D-TOU-B-N $	12,010	955,632	637	18,854	0.0796
31	D-TOU-B-N2	24,092	1,620,493	1,988	12,119	0.0673
32	D-TOU-B-N2 $	6,484	298,645	468	13,855	0.0461
33	D-TOU-B-SDP	57,329	10,542,663	4,115	13,932	0.1839
34	D-TOU-B-SDP @	132	11,955	6	22,000	0.0906
35	D-TOU-B-SDP $	14,654	1,701,053	984	14,892	0.1161
36	D-TOUB-SDPCPP	12	2,428	1	12,000	0.2023
37	D-TOU-B-SDP-N	4,291	508,744	267	16,071	0.1186
38	D-TOU-B-SDPN$	1,247	74,667	78	15,987	0.0599
39	D-TOU-B-SDPN2	2,738	149,300	247	11,085	0.0545
40	D-TOUB-SDPN2$	647	27,911	49	13,204	0.0431
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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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-TOU-B-SDP-O	3,179	621,957	241	13,191	0.1956
3	D-TOU-B-SDPO$	682	86,469	53	12,868	0.1268
4	D-TOU-EV-1	1,713	248,809	566	3,027	0.1452
5	D-TOU-EV-1 @	11	1,625	1	11,000	0.1477
6	D-TOU-EV-1 $	1,338	181,239	289	4,630	0.1355
7	D-TOU-EV-1-N	33	1,847	7	4,714	0.0560
8	D-TOU-EV-1-N $	2	98	2	1,000	0.0490
9	D-TOU-EV-1-N2	25	707	4	6,250	0.0283
10	D-TOU-EV-1N2$	3	186	1	3,000	0.0620
11	D-TOUT	24,650	5,617,920	1,814	13,589	0.2279
12	D-TOUT @	52	6,478	4	13,000	0.1246
13	D-TOUT $	7,725	1,236,190	496	15,575	0.1600
14	D-TOUT-CARE	8,270	1,293,484	584	14,161	0.1564
15	D-TOUT-CARE @	6	206	1	6,000	0.0343
16	D-TOUT-CARE $	2,127	184,172	154	13,812	0.0866
17	D-TOUT-CARE-N	5,722	483,570	536	10,675	0.0845
18	D-TOUT-CAREN$	1,031	27,472	96	10,740	0.0266
19	D-TOUT-CAREN2	994	43,834	100	9,940	0.0441
20	D-TOUTCAREN2$	138	1,818	17	8,118	0.0132
21	D-TOUT-C-SDP	2,241	339,070	156	14,365	0.1513
22	D-TOUT-C-SDP$	546	43,163	37	14,757	0.0791
23	DTOUT-C-SDP-N	1,074	84,348	98	10,959	0.0785
24	DTOUT-C-SDPN$	149	2,491	14	10,643	0.0167
25	DTOUT-C-SDPN2	250	9,390	21	11,905	0.0376
26	DTOUT-CSDPN2$	4	-38	1	4,000	-0.0095
27	DTOUT-C-SDP-O	12	2,127	1	12,000	0.1773
28	DTOUT-C-SDPO$	20	1,766	1	20,000	0.0883
29	DTOUTC-SDPO-N	45	3,253	4	11,250	0.0723
30	DTOUTC-SDPON$	19	-35	2	9,500	-0.0018
31	DTOUTC-SDPON2		476			
32	D-TOUT-N	63,394	6,188,254	6,272	10,107	0.0976
33	D-TOUT-N $	13,458	721,261	1,306	10,305	0.0536
34	D-TOUT-N2	8,749	479,008	880	9,942	0.0548
35	D-TOUT-N2 @	14	439	1	14,000	0.0314
36	D-TOUT-N2 $	1,492	38,476	138	10,812	0.0258
37	D-TOUT-SDP	6,418	1,391,506	458	14,013	0.2168
38	D-TOUT-SDP $	1,055	148,524	85	12,412	0.1408
39	D-TOUT-SDP-N	9,511	897,487	947	10,043	0.0944
40	D-TOUT-SDP-N$	1,559	62,254	157	9,930	0.0399
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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.
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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-TOUT-SDP-N2	808	33,776	83	9,735	0.0418
3	D-TOUT-SDPN2$	185	6,167	19	9,737	0.0333
4	D-TOUT-SDP-O	221	50,362	18	12,278	0.2279
5	D-TOUT-SDP-O$	30	4,393	3	10,000	0.1464
6	DTOUT-SDP-O-N	433	48,411	44	9,841	0.1118
7	DTOUTSDP-O-N$	58	1,614	7	8,286	0.0278
8	D-TOUT-SDPON2	53	1,667	6	8,833	0.0315
9	DWL-A	1,852	598,996	90	20,578	0.3234
10	DWL-A @	12	3,980	1	12,000	0.3317
11	DWL-A $	48	14,245	4	12,000	0.2968
12	DWL-B $	50	6,552	1	50,000	0.1310
13	DWL-C	101	17,956	2	50,500	0.1778
14	GS-1	67	13,927	17	3,941	0.2079
15	GS-2	35	9,682	1	35,000	0.2766
16	OL-1-ALLNITE	1,944	588,424	2,565	758	0.3027
17	OL-1ALLNITE@	2	507	2	1,000	0.2535
18	OL-1ALLNITE $	317	79,809	348	911	0.2518
19	TD-4-C-SDP	4,501	639,267	578	7,787	0.1420
20	TD-4-C-SDP @	12	782			0.0652
21	TD-4-C-SDP $	1,568	107,765	207	7,575	0.0687
22	TD-4-C-SDP-N	149	14,404	19	7,842	0.0967
23	TD-4-C-SDP-N$	20	-101	2	10,000	-0.0051
24	TD-4-C-SDP-N2	3,722	170,551	436	8,537	0.0458
25	TD-4-C-SDPN2@	2	-14			-0.0070
26	TD-4-C-SDPN2$	760	4,583	74	10,270	0.0060
27	TD-4-C-SO	87	13,003	17	5,118	0.1495
28	TD-4-C-SO $	52	3,388	9	5,778	0.0652
29	TD-4-C-SO-N $	1	449			0.4490
30	TD-4-C-SO-N2	217	10,758	26	8,346	0.0496
31	TD-4-C-SO-N2$	58	1,020	5	11,600	0.0176
32	TD-4-F-SDP	241	43,289	22	10,955	0.1796
33	TD-4-F-SDP $	53	5,343	5	10,600	0.1008
34	TD-4-F-SDP-N	9	2,103	1	9,000	0.2337
35	TD-4-F-SDP-N2	125	7,067	17	7,353	0.0565
36	TD-4-F-SDPN2$	10	28	1	10,000	0.0028
37	TD-4-F-SO	33	6,090	4	8,250	0.1845
38	TD-4-F-SO $	12	1,348	1	12,000	0.1123
39	TD-4-F-SO-N $	5	2			0.0004
40	TD-4-F-SO-N2	4	71	1	4,000	0.0178
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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	04/14/2021	End of 2020/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.
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1	ACCOUNT 440 CONTINUED					
2	TD-5-C-SDP	4,817	680,922	627	7,683	0.1414
3	TD-5-C-SDP $	1,436	99,920	187	7,679	0.0696
4	TD-5-C-SDP-N	158	14,251	18	8,778	0.0902
5	TD-5-C-SDP-N $	30	608	4	7,500	0.0203
6	TD-5-C-SDP-N2	79	4,199	10	7,900	0.0532
7	TD-5-C-SDPN2$	4	175	1	4,000	0.0438
8	TD-5-C-SO	163	23,432	24	6,792	0.1438
9	TD-5-C-SO $	39	2,955	5	7,800	0.0758
10	TD-5-F-SDP	260	47,546	24	10,833	0.1829
11	TD-5-F-SDP $	66	7,207	6	11,000	0.1092
12	TD-5-F-SDP-N	10	433	1	10,000	0.0433
13	TD-5-F-SDP-N2	1	-35			-0.0350
14	TD-5-F-SO	28	5,087	4	7,000	0.1817
15	TD-5-F-SO $	8	864	1	8,000	0.1080
16	TD-5-F-SO-N	12	1,153	2	6,000	0.0961
17	TD-5-F-SO-N $	1	2			0.0020
18	TDE-4-F-SDPN	8	8	1	8,000	0.0010
19	TDE-P-F-SDP	32	3,721	1	32,000	0.1163
20	T-DE-PRIMEN1$	1	14	1	1,000	0.0140
21	T-DE-PRIMEN2	106	7,482	12	8,833	0.0706
22	T-DE-PRIMEN2$	3	-49			-0.0163
23	T-DE-P-SDPN1	11	1,089			0.0990
24	T-DEP-SDPON1	13	-23	1	13,000	-0.0018
25	TD-P-C-SDP	1,499	187,716	119	12,597	0.1252
26	TD-P-C-SDP $	245	15,753	19	12,895	0.0643
27	TD-PC-SDPCPP	1	164			0.1640
28	TD-P-C-SDPN $	25	109	1	25,000	0.0044
29	TD-P-C-SDP-N1	130	13,907	10	13,000	0.1070
30	TD-P-C-SDP-N2	83	5,059	8	10,375	0.0610
31	TD-P-C-SDPN2$	8	560	1	8,000	0.0700
32	TD-P-F-SDP	146	22,544	11	13,273	0.1544
33	TD-P-F-SDP-N2	4	70			0.0175
34	TGS1-A	-58	-10,150	2	-29,000	0.1750
35	TGS1-A $	-17	-1,652			0.0972
36	TGS1-A-N	2,359	184,147	570	4,139	0.0781
37	TGS1-A-N $	189	9,354	19	9,947	0.0495
38	TGS1-A-S-N2	2	94			0.0470
39	TGS1-B	6	1,572			0.2620
40	TGS1-B-N	47	5,050	4	11,750	0.1074
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 440 CONTINUED					
2	TGS1-B-N $	62	4,420	4	15,500	0.0713
3	TGS1-D-RTP	2	738	1	2,000	0.3690
4	TGS2B-N-S	120	31,698	4	30,000	0.2642
5	TOU-8-D-SEC $		-510			
6	TOU-8-E-SEC	-6	-1,758			0.2930
7	TOU-D-4	567,098	126,573,655	89,273	6,352	0.2232
8	TOU-D-4 $	172,882	26,397,605	24,957	6,927	0.1527
9	TOU-D-4-C	144,409	21,126,500	26,616	5,426	0.1463
10	TOU-D-4-C $	49,301	3,641,769	8,440	5,841	0.0739
11	TOU-D-4-C-N	2,938	299,311	323	9,096	0.1019
12	TOU-D-4-C-N $	636	16,294	78	8,154	0.0256
13	TOU-D-4-C-N2	51,523	2,928,661	5,688	9,058	0.0568
14	TOU-D-4-C-N2$	10,935	221,114	1,096	9,977	0.0202
15	TOU-D-4-CPP		101			
16	TOU-D-4-CPPN2	5	336			0.0672
17	TOU-D-4-F	2,938	539,972	437	6,723	0.1838
18	TOU-D-4-F $	899	93,575	130	6,915	0.1041
19	TOU-D-4-F-N	58	7,089	9	6,444	0.1222
20	TOU-D-4-F-N $	37	3,938	3	12,333	0.1064
21	TOU-D-4-F-N2	2,070	131,315	243	8,519	0.0634
22	TOU-D-4-F-N2$	409	9,782	43	9,512	0.0239
23	TOU-D-4-N	25,303	3,633,835	2,916	8,677	0.1436
24	TOU-D-4-N $	5,777	364,902	550	10,504	0.0632
25	TOU-D-4-N1 @	19	1,372	1	19,000	0.0722
26	TOU-D-4-N2	279,749	20,581,562	34,582	8,089	0.0736
27	TOU-D-4N2 @	21	643	1	21,000	0.0306
28	TOU-D-4-N2 $	64,939	2,394,855	6,388	10,166	0.0369
29	TOU-D-4-SD-N$	316	21,815	27	11,704	0.0690
30	TOU-D-4-SDN2@	3	93	1	3,000	0.0310
31	TOU-D-4-SDN2$	3,152	86,362	294	10,721	0.0274
32	TOU-D-4SDON2$	150	2,403	14	10,714	0.0160
33	TOU-D-4-SDP	29,181	6,118,204	3,546	8,229	0.2097
34	TOU-D-4-SDP @	3	261	1	3,000	0.0870
35	TOU-D-4-SDP $	6,229	841,695	752	8,283	0.1351
36	TOU-D-4-SDP-N	1,765	242,222	215	8,209	0.1372
37	TOU-D-4-SDPN2	12,765	681,920	1,548	8,246	0.0534
38	TOU-D-4-SDPO	1,160	256,620	140	8,286	0.2212
39	TOU-D-4-SDPO$	223	30,886	27	8,259	0.1385
40	TOU-D-4SDPON	67	8,107	9	7,444	0.1210
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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1	ACCOUNT 440 CONTINUED					
2	TOU-D-4SDPON$	34	2,215	3	11,333	0.0651
3	TOU-D-4SDPON2	633	36,601	93	6,806	0.0578
4	TOU-D-5	535,739	118,879,305	83,274	6,433	0.2219
5	TOU-D-5 @	9	992	1	9,000	0.1102
6	TOU-D-5 $	151,138	22,617,950	21,001	7,197	0.1497
7	TOU-D-5-C	139,872	20,214,901	26,912	5,197	0.1445
8	TOU-D-5-C $	45,186	3,210,626	8,103	5,576	0.0711
9	TOU-D-5-C-N	2,419	236,836	244	9,914	0.0979
10	TOU-D-5-C-N $	918	33,781	84	10,929	0.0368
11	TOU-D-5-C-N2	1,055	72,458	136	7,757	0.0687
12	TOU-D-5-C-N2$	314	3,874	37	8,486	0.0123
13	TOU-D-5-F	2,972	540,942	444	6,694	0.1820
14	TOU-D-5-F $	862	92,447	115	7,496	0.1072
15	TOU-D-5-F-N	166	21,733	15	11,067	0.1309
16	TOU-D-5-F-N $	18	1,044	3	6,000	0.0580
17	TOU-D-5-F-N2	48	4,523	6	8,000	0.0942
18	TOU-D-5-F-N2$	15	269			0.0179
19	TOU-D-5-N	19,870	2,847,494	2,059	9,650	0.1433
20	TOU-D-5-N $	5,190	428,548	494	10,506	0.0826
21	TOU-D-5-N2	9,877	824,360	1,215	8,129	0.0835
22	TOU-D-5-N2 $	2,492	124,432	246	10,130	0.0499
23	TOU-D-5-SD-N$	252	16,976	28	9,000	0.0674
24	TOU-D-5-SDN2$	145	4,479	13	11,154	0.0309
25	TOU-D-5-SDP	32,269	6,755,429	4,148	7,779	0.2093
26	TOU-D-5-SDP $	7,079	965,802	836	8,468	0.1364
27	TOU-D-5-SDP-N	1,270	163,028	144	8,819	0.1284
28	TOU-D-5-SDPN2	704	50,184	88	8,000	0.0713
29	TOU-D-5-SDPO	1,227	268,862	161	7,621	0.2191
30	TOU-D-5-SDPO$	376	57,326	38	9,895	0.1525
31	TOU-D-5SDPON	63	7,842	8	7,875	0.1245
32	TOU-D-5SDPON2	41	2,874	6	6,833	0.0701
33	TOU-D-5SDPON2$	7	149	1	7,000	0.0213
34	TOU-DE-4	3,231	539,774	404	7,998	0.1671
35	TOU-DE-4 $	589	54,768	84	7,012	0.0930
36	TOU-DE-4-F	54	8,093	5	10,800	0.1499
37	TOU-DE-4-F $	6	356	1	6,000	0.0593
38	TOU-DE-4-F-N2	13	1,640	1	13,000	0.1262
39	TOU-DE-4-FN2$	10	785	1	10,000	0.0785
40	TOU-DE-4-N	115	9,185	12	9,583	0.0799
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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	TOU-DE-4-N2	793	36,950	110	7,209	0.0466
3	TOU-DE-4-N2 $	29	769	5	5,800	0.0265
4	TOU-DE-4-SDP	544	83,517	63	8,635	0.1535
5	TOU-DE-4-SDP$	85	7,386	10	8,500	0.0869
6	TOU-DE-4SDPN	20	1,410	2	10,000	0.0705
7	TOU-DE-4SDPN2	142	6,587	14	10,143	0.0464
8	TOU-DE4SDPN2$	15	312	2	7,500	0.0208
9	TOU-DE-4SDPO	11	1,860	1	11,000	0.1691
10	TOU-DE-4SDPO$	13	1,034	2	6,500	0.0795
11	TOU-DE-5	2,734	450,327	363	7,532	0.1647
12	TOU-DE-5 $	489	45,778	61	8,016	0.0936
13	TOU-DE-5-F	11	1,601	1	11,000	0.1455
14	TOU-DE-5-N	52	9,065	5	10,400	0.1743
15	TOU-DE-5-N $	2	-1			-0.0005
16	TOU-DE-5-N2	22	3,153	2	11,000	0.1433
17	TOU-DE-5-N2 $	12	109	1	12,000	0.0091
18	TOU-DE-5-SDP	812	125,213	96	8,458	0.1542
19	TOU-DE-5-SDP$	53	4,540	6	8,833	0.0857
20	TOU-DE-5SDPN2	5	-64			-0.0128
21	TOU-DE5-SDPO	43	7,012	4	10,750	0.1631
22	TOU-DE-P-F	2	279			0.1395
23	TOU-DE-P-FN1	5	52			0.0104
24	TOU-DE-PRIME	1,610	238,686	138	11,667	0.1483
25	TOU-DE-PRIME$	125	10,642	14	8,929	0.0851
26	TOU-DEPRIMEN1	126	14,928	10	12,600	0.1185
27	TOU-DE-P-SDP	357	46,221	31	11,516	0.1295
28	TOU-DE-P-SDP$	13	953	1	13,000	0.0733
29	TOUDEP-SDPN2	25	1,806	2	12,500	0.0722
30	TOUDEP-SDPN2$	3	69			0.0230
31	TOU-DEP-SDPO	46	6,364	4	11,500	0.1383
32	TOU-D-P-C	14,488	1,935,740	1,032	14,039	0.1336
33	TOU-D-P-C $	2,482	183,714	170	14,600	0.0740
34	TOU-DP-C-CPP	12	1,904	1	12,000	0.1587
35	TOU-D-P-C-N1	1,416	149,187	99	14,303	0.1054
36	TOU-D-P-C-N1$	252	8,985	16	15,750	0.0357
37	TOU-D-P-C-N2	1,119	76,218	105	10,657	0.0681
38	TOU-D-P-C-N2$	113	3,347	12	9,417	0.0296
39	TOU-D-P-C-SO	109	15,186	9	12,111	0.1393
40	TOU-D-P-C-SO$	15	983	1	15,000	0.0655
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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	TOUD-PCSO-N2$	8	428	1	8,000	0.0535
3	TOU-D-P-F	1,009	164,534	79	12,772	0.1631
4	TOU-D-P-F $	178	16,917	11	16,182	0.0950
5	TOU-D-P-F-N1	139	13,403	11	12,636	0.0964
6	TOU-D-P-F-N1$	14	1,088	1	14,000	0.0777
7	TOU-D-P-F-N2	88	10,341	8	11,000	0.1175
8	TOU-D-P-F-N2$		13			
9	TOU-D-P-F-SO	12	1,992			0.1660
10	TOU-D-P-F-SO$	8	791	1	8,000	0.0989
11	TOU-D-PRIME	139,801	27,166,579	10,095	13,849	0.1943
12	TOU-D-PRIME @	132	13,659	6	22,000	0.1035
13	TOU-D-PRIME $	28,238	3,760,105	1,932	14,616	0.1332
14	TOUD-PRIMECPP	6	1,030			0.1717
15	TOU-D-PRIMEN1	16,738	2,435,737	1,217	13,753	0.1455
16	TOUDPRIMEN1$	3,376	168,375	207	16,309	0.0499
17	TOU-D-PRIMEN2	18,987	1,453,666	1,805	10,519	0.0766
18	TOUDPRIMEN2 @	3	95	1	3,000	0.0317
19	TOUDPRIMEN2 $	3,237	136,622	294	11,010	0.0422
20	TOU-D-P-SDP	10,455	1,927,876	910	11,489	0.1844
21	TOU-D-P-SDP @	12	1,098	1	12,000	0.0915
22	TOU-D-P-SDP $	2,055	245,071	165	12,455	0.1193
23	TOU-D-P-SDPN1	1,364	159,871	115	11,861	0.1172
24	TOU-DP-SDPN1$	256	9,179	18	14,222	0.0359
25	TOU-D-P-SDPN2	1,075	68,157	114	9,430	0.0634
26	TOU-DP-SDPN2$	200	8,982	15	13,333	0.0449
27	TOU-D-P-SDPO	702	135,085	59	11,898	0.1924
28	TOU-D-P-SDPO$	101	13,151	9	11,222	0.1302
29	TOU-D-PSDPON1	77	18,933	7	11,000	0.2459
30	TOU-DPSDPON1$	8	85	1	8,000	0.0106
31	TOU-D-PSDPON2	89	5,763	8	11,125	0.0648
32	TOU-DPSDPON2$	14	1,077	2	7,000	0.0769
33	TOU-GS1D	28,770	4,433,687	2,185	13,167	0.1541
34	TOU-GS1D @	1,078	72,951	72	14,972	0.0677
35	TOU-GS1D $	7,811	693,143	612	12,763	0.0887
36	TOU-GS1D-C	10	769			0.0769
37	TOU-GS1D-N2	16	3,045	2	8,000	0.1903
38	TOU-GS1D-N2 $	8	789			0.0986
39	TOU-GS1E	12,147	2,482,145	2,829	4,294	0.2043
40	TOU-GS1E @	1,630	145,297	198	8,232	0.0891
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 440 CONTINUED					
2	TOU-GS1E $	50,733	6,436,750	11,001	4,612	0.1269
3	TOU-GS1E-AE	41	7,693	5	8,200	0.1876
4	TOU-GS1E-AE $	57	4,793	3	19,000	0.0841
5	TOU-GS1EAEN2$	4	105	1	4,000	0.0263
6	TOU-GS1E-C $	1	142	1	1,000	0.1420
7	TOU-GS1E-C-CP	4	628	1	4,000	0.1570
8	TOU-GS1E-CPN1	329	37,794	1	329,000	0.1149
9	TOU-GS1E-CPN2	333	29,151	29	11,483	0.0875
10	TOU-GS1E-CPP	135,114	27,177,446	27,896	4,843	0.2011
11	TOU-GS1E-CPP$			3		
12	TOU-GS1E-N1	167	19,141	25	6,680	0.1146
13	TOU-GS1E-N1 $	103	4,410	4	25,750	0.0428
14	TOU-GS1E-N2	67	17,633	8	8,375	0.2632
15	TOU-GS1E-N2 $	209	10,961	16	13,063	0.0524
16	TOU-GS2D	2,989	480,555	17	175,824	0.1608
17	TOU-GS2D @	707	54,451	7	101,000	0.0770
18	TOU-GS2D $	7,110	769,717	61	116,557	0.1083
19	TOU-GS2D-AE	21	3,946	1	21,000	0.1879
20	TOU-GS2D-C $	18	831			0.0462
21	TOU-GS2D-CPP	14,604	2,647,684	144	101,417	0.1813
22	TOU-GS2DCPPN1	137	30,465			0.2224
23	TOU-GS2E-S		-188			
24	TOU-GS2E-S $	27	8,209	2	13,500	0.3040
25	TOU-GS2ES-N1	38	6,707	1	38,000	0.1765
26	TOU-PA2DAPIS$	159	10,907	1	159,000	0.0686
27	TOU-PA2D-N2S	1	981	1	1,000	0.9810
28	TOU-PA2D-N2S$	-1	-170			0.1700
29	TOU-PA2D-S $	37	14,615	13	2,846	0.3950
30	TOU-PA2D-SEC	808	175,767	75	10,773	0.2175
31	TOU-PA2E-S	138	30,199	9	15,333	0.2188
32	TOU-PA2E-S $	1	1,051	1	1,000	1.0510
33	TOU-PA3D-S	2,176	216,539	1	2,176,000	0.0995
34	TPA2-A-N	2	412			0.2060
35	TPA2-A-N $	29	4,831	1	29,000	0.1666
36	TPA2-B-N		133			
37	TPA2-B-S-N	8	2,129	1	8,000	0.2661
38	TPA2E-5T8S	28	5,004	1	28,000	0.1787
39	OTHER ADJUSTMENTS		-9,279,009	-12		
40	TOTAL ACCOUNT 440	32,475,081	5,359,481,855	4,516,288	7,191	0.1650
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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1						
2	ACCOUNT 442					
3	AL-2	759	47,841	6	126,500	0.0630
4	AL-2 @		-1			
5	AL-2 $	-74	-3,706	3	-24,667	0.0501
6	AL-2-F	90,703	7,387,394	6,640	13,660	0.0814
7	AL-2-F @	3,313	99,618	65	50,969	0.0301
8	AL-2-F $	14,920	730,953	1,365	10,930	0.0490
9	AL-2-F-N1	37	859			0.0232
10	D	-71	-12,236			0.1723
11	D $	-48	-7,214			0.1503
12	DMS-2	82	26,446	1	82,000	0.3225
13	DMS-2 $	-15	7,175			-0.4783
14	DMS-2-N	-1	-560			0.5600
15	DMS-2-N2	-6	-1,747			0.2912
16	DMS-3	101	20,541			0.2034
17	D-TOU-EV-1			1		
18	GS-1	5,103	959,358	502	10,165	0.1880
19	GS-1 $	38	4,146	8	4,750	0.1091
20	GS-1-N2	-2	-320			0.1600
21	GS-2	7,888	1,449,626	83	95,036	0.1838
22	GS-2 $		121	1		
23	LS-1-ALLNITE	10,851	3,819,131	2,562	4,235	0.3520
24	LS1-ALLNITE@	119	23,463	7	17,000	0.1972
25	LS1-ALLNITE $	3,413	899,070	433	7,882	0.2634
26	LS-1-MIDNITE	6	2,110	1	6,000	0.3517
27	LS1-TAP	108	32,352			0.2996
28	LS-2	2,176	242,713	214	10,168	0.1115
29	LS-2 @	9	594	2	4,500	0.0660
30	LS-2 $	225	15,585	34	6,618	0.0693
31	LS-2-B	33	5,708	8	4,125	0.1730
32	LS-3	18,550	1,675,611	3,094	5,995	0.0903
33	LS-3 @	1,064	42,914	150	7,093	0.0403
34	LS-3 $	2,833	169,489	491	5,770	0.0598
35	MARCH-AFB-DT	38,745	1,983,509	1	38,745,000	0.0512
36	OL-1-ALLNITE	7,019	1,790,904	4,383	1,601	0.2552
37	OL-1ALLNITE@	89	14,446	37	2,405	0.1623
38	OL-1ALLNITE $	1,502	325,986	914	1,643	0.2170
39	PA-1	105	16,718	5	21,000	0.1592
40	PA-2	973	133,706	6	162,167	0.1374
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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1	ACCOUNT 442 CONTINUED					
2	T8A-S-P	5,696	574,619	1	5,696,000	0.1009
3	T8A-S-S		690			
4	T8A-S-T	9,307	751,078	1	9,307,000	0.0807
5	T8BAPSECPPN-S		-285			
6	T8D-APSECPPP	10,960	1,510,111	5	2,192,000	0.1378
7	T8D-APSECPPS	8,838	1,319,198	5	1,767,600	0.1493
8	T8D-APSE-N1S	1,403	206,650	1	1,403,000	0.1473
9	T8D-DAPSESN2	2,079	322,563	4	519,750	0.1552
10	T8-DRTP-PSTBY	6,482	869,080	2	3,241,000	0.1341
11	T8-DRTP-TSTBY	28,061	2,448,443	2	14,030,500	0.0873
12	T8-E-APS-P-N1	-814	-92,491			0.1136
13	T8-E-APS-S-N1	-679	-60,487			0.0891
14	T8-RTP-DL-S #		37,462			
15	T8-S-APSE-P	1,479	267,178	1	1,479,000	0.1806
16	T8-S-APSE-P @	8,531	461,130	1	8,531,000	0.0541
17	T8-S-BIP-S		-6,946			
18	T8-S-P	88,854	10,155,430	9	9,872,667	0.1143
19	T8-S-P $	142	12,424			0.0875
20	T8-S-S	11,648	1,523,806	3	3,882,667	0.1308
21	T8-S-S @	5,952	530,400	1	5,952,000	0.0891
22	T8-S-T	94,405	6,762,098	9	10,489,444	0.0716
23	T8-S-T @	69,247	1,620,455	2	34,623,500	0.0234
24	TC-1	37,464	7,367,584	10,459	3,582	0.1967
25	TC-1 @	2,650	308,171	512	5,176	0.1163
26	TC-1 $	9,771	1,404,960	2,936	3,328	0.1438
27	TG2BAPSECPN2P	179	26,671	1	179,000	0.1490
28	TG2BAPSECPN2S		-917			
29	TG2BAPSECPPNS	9	1,551			0.1723
30	TG3BAPSECPN2S	77	15,850			0.2058
31	TG3BAPSECPPNS	497	96,362	1	497,000	0.1939
32	TGS1-A	1,642	136,666	89	18,449	0.0832
33	TGS1-A @	3	8,909			2.9697
34	TGS1-A $	488	37,278	25	19,520	0.0764
35	TGS1-A-APSE	102	8,976	3	34,000	0.0880
36	TGS1-A-APSE $	27	2,523			0.0934
37	TGS1-A-APSE-N	382	42,478	22	17,364	0.1112
38	TGS1A-APSE-N$	6	610	1	6,000	0.1017
39	TGS1-A-APSEN2	2	99			0.0495
40	TGS1-AAPSEN2$	26	1,244	1	26,000	0.0478
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.
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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	TGS1-A-CPP	54	8,448	15	3,600	0.1564
3	TGS1-A-CPP-N		-175			
4	TGS1-A-CPP-NS	170	14,000	18	9,444	0.0824
5	TGS1-A-DL #		1,234			
6	TGS1-A-N	14,072	1,245,054	1,165	12,079	0.0885
7	TGS1-A-N $	3,450	132,513	243	14,198	0.0384
8	TGS1-A N2 @	6	196			0.0327
9	TGS1-A-P	147	23,576	9	16,333	0.1604
10	TGS1-A-P $	31	2,700	2	15,500	0.0871
11	TGS1-A-P-CPP	27	4,486	3	9,000	0.1661
12	TGS1A-S-CPPN2	13	174	1	13,000	0.0134
13	TGS1-A-S-N2	851	79,247	51	16,686	0.0931
14	TGS1-A-S-N2 $	98	7,170	9	10,889	0.0732
15	TGS1-B	-37	-8,446	9	-4,111	0.2283
16	TGS1-B @	35	20,206	1	35,000	0.5773
17	TGS1-B $	-87	-5,940	4	-21,750	0.0683
18	TGS1-B-APSE	1	200			0.2000
19	TGS1-B-APSE-N	54	6,702	1	54,000	0.1241
20	TGS1-B-APSEN$	11	1,346	1	11,000	0.1224
21	TGS1-B-CN2	3	42			0.0140
22	TGS1-B-CN2 $	22	462			0.0210
23	TGS1-B-N	2,085	281,988	82	25,427	0.1352
24	TGS1-B-N @	26	1,961	1	26,000	0.0754
25	TGS1-B-N $	758	60,443	25	30,320	0.0797
26	TGS1-B-N2	366	34,086	10	36,600	0.0931
27	TGS1-B-N2 @	-6	-786			0.1310
28	TGS1-B-N2 $	103	4,511	2	51,500	0.0438
29	TGS1-B-P-STBY	60	9,291	2	30,000	0.1549
30	TGS1-B-S		660			
31	TGS1-B-S-APSE	39	9,796			0.2512
32	TGS1-B-S-STBY	1	1,100	2	500	1.1000
33	TGS1C-STANDBY	6	1,757			0.2928
34	TGS1-D-RTP	74	14,870	14	5,286	0.2009
35	TGS1-D-RTP-S	5	1,544	1	5,000	0.3088
36	TGS2AAPSE-N2S	22	3,729			0.1695
37	TGS2A-APSE-S		-1			
38	TGS2A-DL-S #		474			
39	TGS2A-N2-S	10	2,114			0.2114
40	TGS2A-N-S	1,894	265,398			0.1401
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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	TGS2A-N-S $	128	10,472			0.0818
3	TGS2A-S	-1,201	-249,968	2	-600,500	0.2081
4	TGS2A-S @		17,759			
5	TGS2A-S $	-77	-5,636	1	-77,000	0.0732
6	TGS2BAPSEN1S$	1,399	157,798	16	87,438	0.1128
7	TGS2BAPSE-N-S	5,232	845,132	28	186,857	0.1615
8	TGS2BAPSEN-S@	2,787	229,686	12	232,250	0.0824
9	TGS2B-APSE-S	3,326	528,367	17	195,647	0.1589
10	TGS2B-APSE-S@	73	5,725			0.0784
11	TGS2B-APSE-S$	152	17,720			0.1166
12	TGS2BAPSE-SN2	631	122,816	8	78,875	0.1946
13	TGS2B-C-N-S	392	27,283	1	392,000	0.0696
14	TGS2B-CPP-N2S	240	45,828	2	120,000	0.1910
15	TGS2B-CPP-N-S	7,895	1,279,109	23	343,261	0.1620
16	TGS2B-CPP-S	1,257	200,194	8	157,125	0.1593
17	TGS2B-CPP-S $	-293	-8,673			0.0296
18	TGS2B-DL-S #		20,858			
19	TGS2B-N2-S	6,595	1,042,211	50	131,900	0.1580
20	TGS2B-N2-S @	525	34,945	1	525,000	0.0666
21	TGS2B-N2-S $	2,483	287,093	18	137,944	0.1156
22	TGS2B-N-P	666	106,809	2	333,000	0.1604
23	TGS2B-N-S	68,295	11,457,136	420	162,607	0.1678
24	TGS2B-N-S @	6,457	583,554	26	248,346	0.0904
25	TGS2B-N-S $	18,739	1,982,169	119	157,471	0.1058
26	TGS2B-P	251	50,876	2	125,500	0.2027
27	TGS2B-P @	801	43,843	1	801,000	0.0547
28	TGS2B-S	5,643	390,712	67	84,224	0.0692
29	TGS2B-S @	2,619	463,402	8	327,375	0.1769
30	TGS2B-S $	1,027	62,674	12	85,583	0.0610
31	TGS2BS-APSE-S	52	1,082	1	52,000	0.0208
32	TGS2B-S-P	1,083	176,652	3	361,000	0.1631
33	TGS2B-S-S	131	49,947	1	131,000	0.3813
34	TGS2B-S-T	131	23,762	1	131,000	0.1814
35	TGS2B-T	345	41,446	1	345,000	0.1201
36	TGS2D-C CPP	3,626	437,173	21	172,667	0.1206
37	TGS2D-CPPNEM2	19,032	3,485,694	155	122,787	0.1831
38	TGS2-D-RTP	1,467	285,289	7	209,571	0.1945
39	TGS2RAPSE-N2S	6,717	741,553	52	129,173	0.1104
40	TGS2RAPSEN2S$	202	22,756	1	202,000	0.1127
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 442 CONTINUED					
2	TGS2RAPSE-N-P	154	15,608	1	154,000	0.1014
3	TGS2RAPSE-N-S	13,063	1,587,912	123	106,203	0.1216
4	TGS2RAPSEN-S@	1,153	130,325	10	115,300	0.1130
5	TGS2RAPSEN-S$	5,597	566,691	56	99,946	0.1012
6	TGS2-R-APSE-S	55	11,392	1	55,000	0.2071
7	T-GS2R-CSN1$	131	6,614	1	131,000	0.0505
8	TGS2-R-N2-S	10,439	1,277,350	74	141,068	0.1224
9	TGS2-R-N2-S @	171	14,587	1	171,000	0.0853
10	TGS2-R-N2-S $	940	88,521	9	104,444	0.0942
11	TGS2-R-N-P	723	87,970	3	241,000	0.1217
12	TGS2-R-N-S	75,410	10,234,410	627	120,271	0.1357
13	TGS2-R-N-S @	3,836	419,201	24	159,833	0.1093
14	TGS2-R-N-S $	21,770	2,180,483	178	122,303	0.1002
15	TGS2-R-S	1,115	208,244	7	159,286	0.1868
16	TGS2-R-S $	299	23,372	1	299,000	0.0782
17	TGS2-B-CPPN2S	1,994	298,251	3	664,667	0.1496
18	TGS3-B-CPPN-S	18,211	2,764,496	21	867,190	0.1518
19	TGS3-CPP-N-S	4,391	667,890			0.1521
20	TGS3-CPP-S	-4,812	-754,057			0.1567
21	TGS3-CPP-S $	45	4,747			0.1055
22	T-GS3D-BIPN2S	429	81,281	1	429,000	0.1895
23	TGS3-DCPNEM2		-2,007			
24	TGS3-DCPP-N2S	8,463	1,273,390	7	1,209,000	0.1505
25	TGS3-D-RTP	4,357	867,737	7	622,429	0.1992
26	TGS3D-RTP-BIP	2,981	512,072	3	993,667	0.1718
27	TGS3D-STBY-S@	3,350	253,089	2	1,675,000	0.0755
28	TGS3D-STBY-T@	133	4,980			0.0374
29	T-GS3EAEN1S	756	112,742	1	756,000	0.1491
30	T-GS3EAEN1S $	148	10,057	1	148,000	0.0680
31	T-GS3EAEN2S	1,900	214,283	8	237,500	0.1128
32	T-GS3EAEN2S $	225	17,505			0.0778
33	TGS3-RAPSEN2P	101	1,065			0.0105
34	TGS3-RAPSEN2S	7,119	838,973	25	284,760	0.1178
35	TGS3RAPSEN2S@	2,274	166,831	2	1,137,000	0.0734
36	TGS3RAPSEN2S$	98	9,261	1	98,000	0.0945
37	TGS3RAPSE-N-P	2,673	268,508	5	534,600	0.1005
38	TGS3RAPSEN-P$	2,132	157,068	3	710,667	0.0737
39	TGS3RAPSE-N-S	19,582	2,373,178	54	362,630	0.1212
40	TGS3RAPSEN-S@	114	20,191	2	57,000	0.1771
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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1	ACCOUNT 442 CONTINUED					
2	TGS3RAPSEN-S$	2,639	250,242	7	377,000	0.0948
3	TGS3-R-APSE-S	-342	-51,729	1	-342,000	0.1513
4	TGS3R-APSE-S@	-316	-27,230	1	-316,000	0.0862
5	TGS3-R-BIPN-S	327	53,697	1	327,000	0.1642
6	TGS3-R-BIPNS$	93	14,283			0.1536
7	TGS3-R-N2-P	1,304	104,750	2	652,000	0.0803
8	TGS3-R-N2-S	9,725	1,255,334	25	389,000	0.1291
9	TGS3-R-N2S $	294	52,858	1	294,000	0.1798
10	TGS3-R-N-P	9,821	1,068,598	14	701,500	0.1088
11	TGS3-R-N-P @	583	40,988	1	583,000	0.0703
12	TGS3-R-N-P $	1,361	109,171	2	680,500	0.0802
13	TGS3-R-N-S	102,489	13,424,921	201	509,896	0.1310
14	TGS3-R-N-S @	82,971	6,340,751	73	1,136,589	0.0764
15	TGS3-R-N-S $	12,492	1,320,059	31	402,968	0.1057
16	TGS3-R-S	-2,144	-284,337			0.1326
17	TGS3-R-S @	2,142	185,857	2	1,071,000	0.0868
18	TOU8-CPP-P		-9,617			
19	TOU8-CPP-S	11	-12,971			-1.1792
20	TOU8-CPP-S-N2	105	15,926			0.1517
21	TOU8-CPP-T	-4,011	-440,950			0.1099
22	TOU-8-D-API-S	1,213	185,256			0.1527
23	TOU-8-D-APSE	56,732	8,379,484	29	1,956,276	0.1477
24	TOU-8-D-APSE$	10,299	968,751	8	1,287,375	0.0941
25	TOU-8-D-APSEP	12,202	1,960,335	7	1,743,143	0.1607
26	TOU-8-DAPSEP@	27,710	1,943,673	9	3,078,889	0.0701
27	TOU-8-DAPSEP$	1,445	153,302	1	1,445,000	0.1061
28	TOU-8-DAPSES@	13,946	1,161,468	8	1,743,250	0.0833
29	TOU-8-D-APSET	35,398	3,116,345	1	35,398,000	0.0880
30	TOU-8-DAPSET@	92,662	3,267,045	1	92,662,000	0.0353
31	TOU8D-BIPN1-T	37,727	3,392,256	1	37,727,000	0.0899
32	TOU-8-D-BIP-P	474,498	52,485,764	40	11,862,450	0.1106
33	TOU-8-D-BIPP@	233,902	11,116,029	19	12,310,632	0.0475
34	TOU-8-D-BIPP$	9,201	1,003,858	3	3,067,000	0.1091
35	TOU-8-D-BIP-S	3,045,148	428,341,618	904	3,368,527	0.1407
36	TOU-8-D-BIPS@	242,725	14,709,536	40	6,068,125	0.0606
37	TOU-8-D-BIPS$	99,198	7,988,562	20	4,959,900	0.0805
38	TOU-8-D-BIP-T	1,010,885	79,301,777	18	56,160,278	0.0784
39	TOU-8-D-BIPT@	922,046	14,378,065	9	102,449,556	0.0156
40	TOU-8-D-BIPT$	66,959	2,406,696	2	33,479,500	0.0359
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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1	ACCOUNT 442 CONTINUED					
2	TOU-8-D-CPP		-20,610			
3	TOU-8-D-CPP-P	237,331	33,513,517	64	3,708,297	0.1412
4	TOU-8DCPPPN2	5,911	783,426	1	5,911,000	0.1325
5	TOU-8-D-CPP-S	801,891	121,006,422	314	2,553,793	0.1509
6	TOU-8-DCPPSN2	10,326	1,503,252	5	2,065,200	0.1456
7	TOU-8-D-CPP-T	63,446	7,574,392	9	7,049,556	0.1194
8	TOU-8-D-DL #		1,543,199			
9	TOU-8-D-EDWP	26,103	2,069,432	1	26,103,000	0.0793
10	TOU-8-D-EDWT	108,785	5,714,543	2	54,392,500	0.0525
11	TOU-8-DL-S#		5,037,664			
12	TOU-8-D-N1P @	12,006	889,351	1	12,006,000	0.0741
13	TOU-8-D-N1P $	143	11,958			0.0836
14	TOU-8-D-N1S @	86,944	6,747,091	25	3,477,760	0.0776
15	TOU-8-D-N1T @	39,339	1,771,243			0.0450
16	TOU-8-D-N2		-3,500			
17	TOU-8-D-N2 @		-10,407			
18	TOU-8-D-N2-P	28,485	3,582,260	3	9,495,000	0.1258
19	TOU-8-D-N2-S	67,031	9,558,248	14	4,787,929	0.1426
20	TOU-8-D-P	1,600,348	201,713,365	231	6,927,913	0.1260
21	TOU-8-D-P-N1	93,694	11,390,705	7	13,384,857	0.1216
22	TOU-8-D-PRI @	1,342,297	78,468,919	120	11,185,808	0.0585
23	TOU-8-D-PRI $	333,961	27,684,097	46	7,260,022	0.0829
24	TOU-8-DPRIN2@	6,158	410,920	1	6,158,000	0.0667
25	TOU8D-RPBPN1P	4,286	762,528	1	4,286,000	0.1779
26	TOU8D-RPBPN1T	205,236	18,830,726	1	205,236,000	0.0918
27	TOU-8-D-RTP	65,560	10,982,659	34	1,928,235	0.1675
28	TOU8D-RTPBIPP	31,200	4,719,111	7	4,457,143	0.1513
29	TOU8D-RTPBIPS	46,949	6,450,291	11	4,268,091	0.1374
30	TOU8D-RTPBIPT	14,673	1,577,598	1	14,673,000	0.1075
31	TOU-8-D-RTP-P	22,165	3,689,410	8	2,770,625	0.1665
32	TOU8-D-RTP-S		300			
33	TOU-8-D-RTP-T	8,150	742,951	2	4,075,000	0.0912
34	TOU-8-D-SEC @	1,379,271	96,016,496	356	3,874,357	0.0696
35	TOU-8-D-SEC $	686,273	60,029,127	226	3,036,606	0.0875
36	TOU-8-DSECN2@	26,984	2,052,120	5	5,396,800	0.0760
37	TOU-8-DSECN2$	1,455	173,684	1	1,455,000	0.1194
38	TOU-8-D-S-N1	24,217	3,405,000	5	4,843,400	0.1406
39	TOU-8-D-SUB @	1,106,121	31,690,157	28	39,504,321	0.0286
40	TOU-8-D-SUB $	125,469	5,948,639	5	25,093,800	0.0474
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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.
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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	TOU-8-DSUBN2@	41,175	1,145,425	1	41,175,000	0.0278
3	TOU-8-D-T	1,027,337	92,601,502	33	31,131,424	0.0901
4	TOU-8-D-T-N1	26,251	2,443,162	2	13,125,500	0.0931
5	TOU-8-E $	324	36,670	1	324,000	0.1132
6	TOU-8-E-CPP-S	-238	-24,940			0.1048
7	TOU-8-E-N1		-5,413			
8	TOU-8-E-N1-P	13,284	1,889,586	5	2,656,800	0.1422
9	TOU-8-E-N1-P@	6,294	483,153	1	6,294,000	0.0768
10	TOU-8-E-N1-P$	8,254	685,727	1	8,254,000	0.0831
11	TOU-8-E-N1-S	19,718	2,893,476	8	2,464,750	0.1467
12	TOU-8-E-N1-S@	15,318	1,265,576	6	2,553,000	0.0826
13	TOU-8-E-N1-S$	5,225	476,865	3	1,741,667	0.0913
14	TOU-8-E-N1-T	18,371	1,766,339	1	18,371,000	0.0961
15	TOU-8-E-N2-P	1,194	157,644	1	1,194,000	0.1320
16	TOU-8-E-N2-S	7,703	1,037,856	4	1,925,750	0.1347
17	TOU-8-E-N2-S$	33	3,538			0.1072
18	TOU-8-E-P @	18,377	1,423,787	2	9,188,500	0.0775
19	TOU-8-E-PRI	23,086	3,051,019	6	3,847,667	0.1322
20	TOU-8-E-PRI $	5,118	402,903			0.0787
21	TOU-8-E-S @	4,526	354,315	4	1,131,500	0.0783
22	TOU-8-E-SEC	33,046	4,917,521	12	2,753,833	0.1488
23	TOU-8-E-SUB	37,361	4,052,100	7	5,337,286	0.1085
24	TOU8-N-P $	117,179	8,406,219	6	19,529,833	0.0717
25	TOU8-N-S $	8,466	695,585	3	2,822,000	0.0822
26	TOU8-N-T $	8,055	436,176	1	8,055,000	0.0541
27	TOU8-P $	-4	-2,236	1	-4,000	0.5590
28	TOU8R-BIP-N-P	6,438	813,806			0.1264
29	TOU8-R-BIP-P	9,520	1,172,474	1	9,520,000	0.1232
30	TOU8-R-N2-P	15,440	2,097,566	3	5,146,667	0.1359
31	TOU8-R-N2-S	214	-2,085			-0.0097
32	TOU8-R-N2-S $	793	79,369	1	793,000	0.1001
33	TOU8-R-N-P	100,540	11,960,943	30	3,351,333	0.1190
34	TOU8-R-N-P @	29,276	2,224,738	7	4,182,286	0.0760
35	TOU8-R-N-P $	7,811	592,798	4	1,952,750	0.0759
36	TOU8-R-N-S	57,596	6,831,497	32	1,799,875	0.1186
37	TOU8-R-N-S @	28,161	2,423,773	11	2,560,091	0.0861
38	TOU8-R-N-S $	9,685	874,638	7	1,383,571	0.0903
39	TOU8-R-P	4,050	530,603	1	4,050,000	0.1310
40	TOU8-R-S	1,692	241,978	1	1,692,000	0.1430
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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	TOU8-R-S @	2,403	173,637	1	2,403,000	0.0723
3	TOU8-R-T	19,952	1,927,115	1	19,952,000	0.0966
4	TOU8-S $	1	7,567			7.5670
5	TOU-8-S-D	86,970	12,774,890	26	3,345,000	0.1469
6	TOU-8-S-D-AE	839	147,973	1	839,000	0.1764
7	TOU-8-S-DAEP	58,970	8,065,691	1	58,970,000	0.1368
8	TOU-8-S-D-BIP	17,268	2,155,878	3	5,756,000	0.1248
9	TOU-8-S-DBIP@	29,423	1,640,753	6	4,903,833	0.0558
10	TOU-8-S-DBIPP	12,326	1,194,008	4	3,081,500	0.0969
11	TOU-8-S-DBIPT	738,572	55,359,376	6	123,095,333	0.0750
12	TOU-8-S-DBPT@	131,812	-200,341	1	131,812,000	-0.0015
13	TOU-8-S-D-P	192,174	29,726,326	40	4,804,350	0.1547
14	TOU-8-S-D-P @	83,977	5,401,349	9	9,330,778	0.0643
15	TOU-8-S-D-P $	23,599	1,775,390	2	11,799,500	0.0752
16	TOU-8-S-D-T	1,167,949	110,748,083	83	14,071,675	0.0948
17	TOU-8-S-D-T @	116,845	4,869,639	6	19,474,167	0.0417
18	TOU-D-4	-4	-757			0.1893
19	TOU-D-5 $	-2	-102			0.0510
20	TOU-EV-4-S	-14	-8,992			0.6423
21	TOU-EV-4-S @		232			
22	TOU-EV-4-S N2	14	8,176			0.5840
23	TOU-EV-7-D	216	39,354	44	4,909	0.1822
24	TOU-EV-7-D @	2	325	1	2,000	0.1625
25	TOU-EV-7-D $	490	55,775	8	61,250	0.1138
26	TOU-EV-7-E	258	51,872	45	5,733	0.2011
27	TOU-EV-7-E $	67	9,066	16	4,188	0.1353
28	TOU-EV-8	11,107	2,217,435	223	49,807	0.1996
29	TOU-EV-8 @	249	29,455	6	41,500	0.1183
30	TOU-EV-8 $	2,556	312,530	46	55,565	0.1223
31	TOU-EV-8-N2	120	16,181	3	40,000	0.1348
32	TOU-EV-8-N2 $	18	1,780			0.0989
33	TOU-EV9-N2SEC	18	2,539			0.1411
34	TOU-EV-9-PRI	797	108,800	1	797,000	0.1365
35	TOU-EV-9-PRI$	4,360	356,564	2	2,180,000	0.0818
36	TOU-EV-9-SEC	35,665	5,845,470	44	810,568	0.1639
37	TOU-EV-9-SEC$	19,312	1,949,642	15	1,287,467	0.1010
38	TOUG3A-APSE-S	-18	-2,973			0.1652
39	TOUG3B-APSE-S	3,139	473,248	9	348,778	0.1508
40	TOU-GS1D	1,037,079	155,410,381	43,163	24,027	0.1499
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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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	TOU-GS1D @	117,102	8,610,186	10,714	10,930	0.0735
3	TOU-GS1D $	304,481	25,188,468	11,194	27,200	0.0827
4	TOU-GS1D-AE	14,833	2,289,915	374	39,660	0.1544
5	TOU-GS1D-AE @	134	9,682	4	33,500	0.0723
6	TOU-GS1D-AE $	3,477	293,080	94	36,989	0.0843
7	TOU-GS1D-AEN1	2	581			0.2905
8	TOUGS1DAEN2	62	10,720	3	20,667	0.1729
9	TOU-GS1D-C	279	32,770	10	27,900	0.1175
10	TOU-GS1D-C $	61	2,800	3	20,333	0.0459
11	TOU-GS1D-CPP	4	1,047			0.2618
12	TOU-GS1D-N1	798	210,804	42	19,000	0.2642
13	TOU-GS1D-N1 $	532	70,211	18	29,556	0.1320
14	TOU-GS1D-N2	2,099	448,141	118	17,788	0.2135
15	TOU-GS1D-N2 @		-941	1		
16	TOU-GS1D-N2 $	582	83,425	30	19,400	0.1433
17	TOU-GS1D-S	181	32,604	8	22,625	0.1801
18	TOU-GS1E	1,091,150	206,896,702	108,009	10,102	0.1896
19	TOU-GS1E @	32,116	3,053,414	2,417	13,288	0.0951
20	TOU-GS1E $	888,386	99,202,145	94,766	9,375	0.1117
21	TOU-GS1E-AE	33,888	5,876,254	2,563	13,222	0.1734
22	TOU-GS1E-AE @	982	85,528	76	12,921	0.0871
23	TOU-GS1E-AE $	8,328	817,792	683	12,193	0.0982
24	TOU-GS1E-AEN1	143	18,104	9	15,889	0.1266
25	TOU-GS1EAE1$	38	1,636	3	12,667	0.0431
26	TOU-GS1E-AEN2	171	20,322	11	15,545	0.1188
27	TOU-GS1EAEN2$	58	3,306	4	14,500	0.0570
28	TOU-GS1E-C	118	15,981	6	19,667	0.1354
29	TOU-GS1E-C $	307	14,451	14	21,929	0.0471
30	TOU-GS1E-C-CP	485	63,743	29	16,724	0.1314
31	TOU-GS1E-CPN1	1,641	144,196	41	40,024	0.0879
32	TOU-GS1E-CPN2	3,968	396,364	350	11,337	0.0999
33	TOU-GS1E-CPP	1,782,966	334,554,182	195,210	9,134	0.1876
34	TOU-GS1E-CPP$	15	1,323	20	750	0.0882
35	TOU-GS1E-N1	7,132	1,006,765	426	16,742	0.1412
36	TOU-GS1E-N1 $	2,974	138,657	143	20,797	0.0466
37	TOU-GS1E-N2	9,755	1,367,096	714	13,662	0.1401
38	TOU-GS1E-N2 @	121	5,213	4	30,250	0.0431
39	TOU-GS1E-N2 $	2,559	157,709	153	16,725	0.0616
40	TOU-GS1ES	122	23,177	9	13,556	0.1900
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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1	ACCOUNT 442 CONTINUED					
2	TOU-GS1ES $	2	343			0.1715
3	TOU-GS-1-LG	31	5,264	1	31,000	0.1698
4	TOU-GS2D	2,450,711	421,368,646	13,787	177,755	0.1719
5	TOU-GS2D @	1,394,653	111,739,545	5,606	248,779	0.0801
6	TOU-GS2D $	1,966,164	211,961,577	12,750	154,209	0.1078
7	TOU-GS2D-AE	130,088	23,659,458	1,017	127,913	0.1819
8	TOU-GS2D-AE @	99,826	7,094,916	388	257,284	0.0711
9	TOU-GS2D-AE $	40,913	4,734,568	325	125,886	0.1157
10	TOU-GS2D-AEC	188	25,914	3	62,667	0.1378
11	TOU-GS2D-AEC$	424	18,364	2	212,000	0.0433
12	TOU-GS2D-AECP	6,764	1,130,633	24	281,833	0.1672
13	TOU-GS2D-AEN1	1,013	171,883	8	126,625	0.1697
14	TOU-GS2DAEN2	1,360	273,787	14	97,143	0.2013
15	TOU-GS2DAEN2$	425	41,368	4	106,250	0.0973
16	TOU-GS2D-C	1,637	197,116	8	204,625	0.1204
17	TOU-GS2D-C @	1,655	54,787	2	827,500	0.0331
18	TOU-GS2D-C $	2,009	98,187	11	182,636	0.0489
19	TOUGS2DC-CPN2	224	25,535	1	224,000	0.1140
20	TOU-GS2D-C-N1	255	28,497	1	255,000	0.1118
21	TOU-GS2D-CPP	4,385,425	774,600,093	29,493	148,694	0.1766
22	TOU-GS2D-CPP@	13	1,034			0.0795
23	TOU-GS2D-CPP$	86	12,024	5	17,200	0.1398
24	TOU-GS2DCPPN1	3,139	565,785	10	313,900	0.1802
25	TOU-GS2D-DL #		99,694			
26	TOU-GS2D-EDW	983	136,870	5	196,600	0.1392
27	TOU-GS2D-N1	21,045	3,775,071	118	178,347	0.1794
28	TOU-GS2D-N1 @	48	5,524			0.1151
29	TOU-GS2D-N1 $	7,121	770,362	46	154,804	0.1082
30	TOU-GS2D-N2	30,654	5,524,115	185	165,697	0.1802
31	TOU-GS2D-N2 @	1,059	93,469	5	211,800	0.0883
32	TOU-GS2D-N2 $	9,644	1,056,938	68	141,824	0.1096
33	TOU-GS2D-S	10,897	2,278,337	54	201,796	0.2091
34	TOU-GS2D-S $	-298	-30,736	2	-149,000	0.1031
35	TOU-GS2D-SAE	326	66,471	2	163,000	0.2039
36	TOU-GS2E		-117,961			
37	TOU-GS2E $		-14,688			
38	TOU-GS2E-AE	105,484	19,819,263	1,250	84,387	0.1879
39	TOU-GS2E-AE @	2,994	317,980	22	136,091	0.1062
40	TOU-GS2E-AE $	21,024	2,557,669	271	77,579	0.1217
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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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	TOU-GS2E-AEC	34	5,104	20	1,700	0.1501
3	TOU-GS2EAEN1	2,182	377,214	2	1,091,000	0.1729
4	TOU-GS2EAEN1$	240	24,986	28	8,571	0.1041
5	TOU-GS2EAEN2	1,835	304,915	12	152,917	0.1662
6	TOU-GS2EAEN2$	629	47,233	3	209,667	0.0751
7	TOU-GS2E-C	356	44,703			0.1256
8	TOU-GS2E-N1		7,609			
9	TOU-GS2E-N1 $		21,806			
10	TOU-GS2E-N2		-42,183			
11	TOU-GS2E-N2 @		-1,157			
12	TOU-GS2E-N2 $		-3,933			
13	TOU-GS2E-P	7,625	1,374,876	42	181,548	0.1803
14	TOU-GS2E-P $	1,012	103,237	5	202,400	0.1020
15	TOU-GS2EP-N1	457	89,252	1	457,000	0.1953
16	TOU-GS2EP-N1$	48	5,735			0.1195
17	TOU-GS2E-S	1,581,957	306,395,322	17,188	92,038	0.1937
18	TOU-GS2E-S @	28,239	2,849,565	169	167,095	0.1009
19	TOU-GS2E-S $	374,788	47,738,678	4,308	86,998	0.1274
20	TOU-GS2ES-N1	19,683	3,385,638	143	137,643	0.1720
21	TOU-GS2ES-N1$	5,093	512,937	41	124,220	0.1007
22	TOU-GS2ES-N2	24,535	4,187,709	240	102,229	0.1707
23	TOU-GS2ES-N2@	843	65,106	3	281,000	0.0772
24	TOU-GS2ES-N2$	3,528	378,202	40	88,200	0.1072
25	TOU-GS2E-T	247	29,247	1	247,000	0.1184
26	TOU-GS2-R-S	836	174,658	8	104,500	0.2089
27	TOU-GS-3-A-S	-861	-118,185			0.1373
28	TOU-GS3-A-S @		4,987			
29	TOU-GS3-A-S-N	740	93,240			0.1260
30	TOU-GS3-A-SN2	121	22,318			0.1844
31	TOU-GS3-A-T @		-193			
32	TOU-GS3B-C-P@	743	26,206	1	743,000	0.0353
33	TOU-GS3BC-S-N	629	68,771	1	629,000	0.1093
34	TOU-GS3-B-P @	339	33,047			0.0975
35	TOU-GS3-B-P-N	1,107	160,536	2	553,500	0.1450
36	TOU-GS3B-P-N$	2,816	198,625	1	2,816,000	0.0705
37	TOU-GS-3-B-S	8,664	1,110,802	14	618,857	0.1282
38	TOU-GS3-B-S @	5,032	468,581	3	1,677,333	0.0931
39	TOU-GS3-B-S $	-831	10,912	4	-207,750	-0.0131
40	TOUGS3BS-BIP@		2,688	1		
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 442 CONTINUED					
2	TOUGS3BS-CPP	2,682	394,885	2	1,341,000	0.1472
3	TOU-GS3-B-S-N	43,059	5,897,145	41	1,050,220	0.1370
4	TOUGS3-B-S-N@	20,506	1,587,394	16	1,281,625	0.0774
5	TOU-GS3B-S-N$	16,175	1,583,492	18	898,611	0.0979
6	TOU-GS3-B-SN2	7,688	1,155,556	12	640,667	0.1503
7	TOUGS3-B-SN2@	69	9,074			0.1315
8	TOU-GS3B-SN2$	448	42,680	1	448,000	0.0953
9	TOU-GS3B-S-S	1,002	141,172			0.1409
10	TOU-GS3B-S-S$	-1,002	-74,302			0.0742
11	TOU-GS3B-S-T	143	17,656			0.1235
12	TOU-GS3-B-T	456	75,676			0.1660
13	TOU-GS3-B-T $	-439	-57,909			0.1319
14	TOU-GS3D-AE	65,090	10,293,489	80	813,625	0.1581
15	TOU-GS3D-AE @	15,231	1,315,978	17	895,941	0.0864
16	TOU-GS3D-AE $	24,293	2,383,497	32	759,156	0.0981
17	TOU-GS3D-AECP	10,587	1,804,928	18	588,167	0.1705
18	TOU-GS3D-AEN2	1,748	307,269	6	291,333	0.1758
19	TOU-GS3DAEN2@	83	13,983			0.1685
20	TOU-GS3-DAES	1,541	261,357			0.1696
21	TOU-GS3-DAES$	-716	-72,742	1	-716,000	0.1016
22	TOUGS3D-BIPP	8,110	1,115,753	6	1,351,667	0.1376
23	TOUGS3D-BIPS	76,378	11,027,181	50	1,527,560	0.1444
24	TOUGS3D-BIPS@	50,609	4,001,309	34	1,488,500	0.0791
25	TOUGS3D-BIPS$	19,611	1,754,506	14	1,400,786	0.0895
26	TOU-GS3-D-C	5,998	614,460	6	999,667	0.1024
27	TOU-GS3-D-C @	1,013	42,644	1	1,013,000	0.0421
28	TOU-GS3-D-C $	1,987	77,432	2	993,500	0.0390
29	TOU-GS3D-C-CP	1,125	110,746	1	1,125,000	0.0984
30	TOUGS3D-CPN1S	6,374	1,026,735	2	3,187,000	0.1611
31	TOU-GS3D-CP-P	27,778	4,176,883	27	1,028,815	0.1504
32	TOU-GS3D-CP-S	1,049,597	166,253,439	1,158	906,388	0.1584
33	TOU-GS3-DCPS$	2,093	164,967	1	2,093,000	0.0788
34	TOU-GS3-D-DL#		707			
35	TOU-GS3D-EDW	477	60,261	1	477,000	0.1263
36	TOUGS3D-N1S	9,551	1,640,103	12	795,917	0.1717
37	TOUGS3D-N1S @	12,749	900,421	8	1,593,625	0.0706
38	TOUGS3D-N1S $	1,387	146,123	2	693,500	0.1054
39	TOUGS3D-N2P	326	50,186			0.1539
40	TOUGS3D-N2P @	182	18,640			0.1024
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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	TOUGS3D-N2P $	111	10,572			0.0952
3	TOUGS3D-N2S	15,591	2,379,225	20	779,550	0.1526
4	TOUGS3D-N2S @	6,431	514,331	6	1,071,833	0.0800
5	TOUGS3D-N2S $	9,154	859,202	8	1,144,250	0.0939
6	TOU-GS3-D-P	50,085	7,613,574	46	1,088,804	0.1520
7	TOU-GS3-D-P @	13,780	1,176,831	11	1,252,727	0.0854
8	TOU-GS3-D-P $	26,710	2,462,287	25	1,068,400	0.0922
9	TOU-GS3-D-S	2,246,323	339,187,059	2,001	1,122,600	0.1510
10	TOU-GS3-D-S @	1,522,766	102,445,384	1,082	1,407,362	0.0673
11	TOU-GS3-D-S $	775,244	73,440,469	756	1,025,455	0.0947
12	TOU-GS3-D-SP	4,785	868,758	5	957,000	0.1816
13	TOU-GS3-D-SS	20,626	3,072,060	17	1,213,294	0.1489
14	TOU-GS3-D-SS$	-894	-68,896	1	-894,000	0.0771
15	TOU-GS3-D-ST	8,118	1,553,185	13	624,462	0.1913
16	TOU-GS3-D-T	7,289	1,072,931	5	1,457,800	0.1472
17	TOU-GS3-D-T @	808	39,715	1	808,000	0.0492
18	TOU-GS3-D-T $	-311	-60,111	2	-155,500	0.1933
19	TOU-GS3-E		-2,728			
20	TOU-GS3E-AEN1		2,154			
21	TOU-GS3E-AEP	1,780	274,507	3	593,333	0.1542
22	TOU-GS3E-AEP@	1,518	129,501	1	1,518,000	0.0853
23	TOU-GS3E-AES	79,507	13,252,876	231	344,186	0.1667
24	TOU-GS3E-AES@	12,860	1,181,908	38	338,421	0.0919
25	TOU-GS3E-AES$	14,024	1,442,943	31	452,387	0.1029
26	TOU-GS3-E-BPS	8,931	1,458,930	12	744,250	0.1634
27	TOU-GS3-E-BPS@	1,805	152,851	1	1,805,000	0.0847
28	TOU-GS3-E-BPS$	779	65,867	2	389,500	0.0846
29	TOU-GS3-E-N1P	845	131,952	2	422,500	0.1562
30	TOU-GS3E-N1P$	256	23,454			0.0916
31	TOU-GS3-E-N1S	19,734	3,216,025	33	598,000	0.1630
32	TOU-GS3-E-N1S@	9,929	947,900	12	827,417	0.0955
33	TOU-GS3E-N1S$	1,803	188,333	2	901,500	0.1045
34	TOU-GS3-E-N2		-66,677			
35	TOU-GS3-E-N2$		-1,095			
36	TOU-GS3E-N2S	16,634	2,439,656	31	536,581	0.1467
37	TOU-GS3E-N2S@	4,072	319,321	3	1,357,333	0.0784
38	TOU-GS3E-N2S$	2,253	208,299	3	751,000	0.0925
39	TOU-GS3-E-P	16,685	2,779,881	19	878,158	0.1666
40	TOU-GS3-E-P @	1,012	86,206	1	1,012,000	0.0852
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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1	ACCOUNT 442 CONTINUED					
2	TOU-GS3-EP $	1,475	154,211	3	491,667	0.1045
3	TOU-GS3-E-S	424,280	70,948,645	635	668,157	0.1672
4	TOU-GS3-E-S @	32,196	3,106,849	43	748,744	0.0965
5	TOU-GS3-ES $	84,301	9,084,009	124	679,847	0.1078
6	TOU-GS3-E-T	228	24,881			0.1091
7	TOU-GS3-R-S	607	73,023	1	607,000	0.1203
8	TOU-PA2D		-30,355	1		
9	TOU-PA2D $		-4,208			
10	TOU-PA2D-APIP	1,141	105,592	2	570,500	0.0925
11	TOU-PA2D-APIS	74,478	8,963,618	376	198,080	0.1204
12	TOU-PA2DAPIS@	2,208	105,261	5	441,600	0.0477
13	TOU-PA2DAPIS$	1,924	125,132	11	174,909	0.0650
14	TOU-PA2D-CP-S	9,626	1,312,105	35	275,029	0.1363
15	TOU-PA2D-N1S	4,838	562,232	35	138,229	0.1162
16	TOU-PA2D-N1S$	352	39,600	10	35,200	0.1125
17	TOU-PA2D-N2S	4,050	495,662	59	68,644	0.1224
18	TOU-PA2D-N2S$	385	37,080	6	64,167	0.0963
19	TOU-PA2D-P	5,480	682,179	19	288,421	0.1245
20	TOU-PA2D-P $	3,608	226,208	12	300,667	0.0627
21	TOU-PA2D-RTP	1,073	154,357	6	178,833	0.1439
22	TOU-PA2D-S	488	55,774	3	162,667	0.1143
23	TOU-PA2D-S @	27,860	1,719,206	172	161,977	0.0617
24	TOU-PA2D-S $	160,903	14,905,379	2,217	72,577	0.0926
25	TOU-PA2D-SEC	852,613	126,941,021	10,976	77,680	0.1489
26	TOU-PA2E		-7,664			
27	TOU-PA2E $		-4,856			
28	TOU-PA2EAPIN1		-5,094			
29	TOU-PA2EAPIN2		-27,844			
30	TOU-PA2E-APIS	17,304	2,431,267	159	108,830	0.1405
31	TOUPA2E-APIS@		274			
32	TOU-PA2EAPIS$	1,232	107,353	6	205,333	0.0871
33	TOU-PA2EAPN1S	758	80,069	7	108,286	0.1056
34	TOU-PA2EAPN2S	7,508	728,439	35	214,514	0.0970
35	TOU-PA2E-CPPS		278			
36	TOU-PA2E-DL #		32			
37	TOU-PA2E-N1		-35,094			
38	TOU-PA2E-N1P	20	-12,610	1	20,000	-0.6305
39	TOU-PA2E-N1S	5,291	660,982	47	112,574	0.1249
40	TOU-PA2E-N1$	258	21,478	2	129,000	0.0832
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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1	ACCOUNT 442 CONTINUED					
2	TOU-PA2E-N2		-78,201			
3	TOU-PA2E-N2-S	24,641	2,557,301	165	149,339	0.1038
4	TOU-PA2E-P	220	49,154	5	44,000	0.2234
5	TOU-PA2E-P@	365	29,430	1	365,000	0.0806
6	TOU-PA2E-P $	459	37,870	2	229,500	0.0825
7	TOU-PA2-E-S	-159	-23,393	1	-159,000	0.1471
8	TOU-PA2E-S	280,144	48,947,293	5,664	49,460	0.1747
9	TOU-PA2E-S@	1,054	78,423	11	95,818	0.0744
10	TOU-PA2E-S $	37,097	4,261,539	548	67,695	0.1149
11	TOU-PA3D-APIP	13,979	1,078,437	3	4,659,667	0.0771
12	TOU-PA3DAPIP@	2,875	100,271	1	2,875,000	0.0349
13	TOU-PA3D-APIS	25,423	2,734,314	29	876,655	0.1076
14	TOU-PA3DAPIS@	61	12,182	1	61,000	0.1997
15	TOU-PA3DAPIS$	2,119	110,185	2	1,059,500	0.0520
16	TOU-PA3DCPN2S	1,016	127,577	1	1,016,000	0.1256
17	TOU-PA3D-CPP	1,105	96,646	1	1,105,000	0.0875
18	TOU-PA3D-CPS	133,521	16,882,324	177	754,356	0.1264
19	TOU-PA3D-N1S	1,913	216,631	2	956,500	0.1132
20	TOU-PA3D-N1S$	405	39,511	1	405,000	0.0976
21	TOU-PA3D-N2		-582			
22	TOU-PA3D-N2S	1,539	205,774	3	513,000	0.1337
23	TOU-PA3D-N2S$	1,702	99,435	1	1,702,000	0.0584
24	TOU-PA3D-P	21,153	2,503,656	17	1,244,294	0.1184
25	TOU-PA3D-P @	16,252	813,688	4	4,063,000	0.0501
26	TOU-PA3D-P $	5,361	337,131	4	1,340,250	0.0629
27	TOU-PA3D-S	534,580	62,302,523	434	1,231,751	0.1165
28	TOU-PA3D-S @	30,656	2,027,668	32	958,000	0.0661
29	TOU-PA3D-S $	108,233	7,969,711	107	1,011,523	0.0736
30	TOU-PA3D-T	28,924	2,403,296	1	28,924,000	0.0831
31	TOU-PA3E		-209			
32	TOU-PA3EAPIN1		785			
33	TOU-PA3EAPIS@	6,844	335,780	5	1,368,800	0.0491
34	TOU-PA3E-N1		-4,548			
35	TOU-PA3E-N1P	11,681	1,380,619	1	11,681,000	0.1182
36	TOU-PA3E-N1P$	4,539	326,954	3	1,513,000	0.0720
37	TOU-PA3E-N1S	11,589	1,225,110	12	965,750	0.1057
38	TOU-PA3E-N1S$		-10,376			
39	TOU-PA3E-N2		-7,382			
40	TOU-PA3E-N2S	13,216	1,460,711	15	881,067	0.1105
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.
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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	TOU-PA3E-P	-522	14,717	5	-104,400	-0.0282
3	TOU-PA3E-P @	141	13,023	1	141,000	0.0924
4	TOU-PA3E-S	180,827	25,067,779	316	572,237	0.1386
5	TOU-PA3E-S @	3,537	288,266	5	707,400	0.0815
6	TOU-PA3E-S $	19,360	1,735,193	32	605,000	0.0896
7	TPA2-A	70,983	9,682,717	443	160,233	0.1364
8	TPA2-A @	1,422	143,119	10	142,200	0.1006
9	TPA2-A $	8,819	860,389	76	116,039	0.0976
10	TPA2-A-API	14,573	1,808,443	76	191,750	0.1241
11	TPA2-A-API $	3,375	202,102	14	241,071	0.0599
12	TPA2-A-API-N	33,150	1,630,536	157	211,146	0.0492
13	TPA2-A-API-N$	657	33,812	3	219,000	0.0515
14	TPA2-A-API-N2	389	5,539	2	194,500	0.0142
15	TPA2-A-N	78,064	5,276,312	493	158,345	0.0676
16	TPA2-A-N $	515	29,689	4	128,750	0.0576
17	TPA2-A-N2	5,546	345,745	27	205,407	0.0623
18	TPA2-A-N2 $	625	32,613	2	312,500	0.0522
19	TPA2-A-P	312	41,016	1	312,000	0.1315
20	TPA2-A-STDBY	297	38,487			0.1296
21	TPA2-B	37,742	3,447,841	97	389,093	0.0914
22	TPA2-B @		855			
23	TPA2-B $	824	54,022	6	137,333	0.0656
24	TPA2-B-API-N		-778	3		
25	TPA2-B-CPP	167	35,878			0.2148
26	TPA2-B-DL #		11,164			
27	TPA2-B-N		-7,965			
28	TPA2-B-N $		-2,692			
29	TPA2-B-P	141	8,737	1	141,000	0.0620
30	TPA2-B-S		530			
31	TPA2B-S-API-N	966	57,840			0.0599
32	TPA2-B-S-N	9,790	885,193	74	132,297	0.0904
33	TPA2-B-S-N $	1,488	81,441	12	124,000	0.0547
34	TPA2-B-S-N2	4,886	409,859	2	2,443,000	0.0839
35	TPA2B-STBY-P	297	20,723	1	297,000	0.0698
36	TPA2B-STBY-S	1,253	164,403			0.1312
37	TPA2D-5T8-APS	465	51,321	2	232,500	0.1104
38	TPA2D-5T8-CPS	448	66,888	5	89,600	0.1493
39	TPA2D-5T8N1S	26	5,150			0.1981
40	TPA2D-5T8N2S	227	37,226			0.1640
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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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	TPA2D-5T8-PRI	189	25,029	1	189,000	0.1324
3	TPA2D-5T8-SEC	52,352	6,354,369	271	193,181	0.1214
4	TPA2D-5T8SEC@	4,989	306,176	17	293,471	0.0614
5	TPA2D-5T8SEC$	4,399	330,209	30	146,633	0.0751
6	TPA2D-API-N1S	48	4,904			0.1022
7	T-PA2D-APIN2S	216	24,113	3	72,000	0.1116
8	TPA2E-5T8APIS	452	65,406	4	113,000	0.1447
9	TPA2E-5T8APS$	412	34,518	2	206,000	0.0838
10	TPA2E-5T8S	47,714	7,803,655	869	54,907	0.1636
11	TPA2E-5T8S @	541	54,407	5	108,200	0.1006
12	TPA2E-5T8S $	3,771	408,116	52	72,519	0.1082
13	TPA2E-5T8S-N1	323	18,118	4	80,750	0.0561
14	TPA2E-5T8S-N2	302	22,070	1	302,000	0.0731
15	TPA3-A $	6,134	565,619	11	557,636	0.0922
16	TPA3-A-API-N	4,801	243,635	9	533,444	0.0507
17	TPA3-ACPP-N1S	274	7,942			0.0290
18	TPA3-A-DL #		1,383			
19	TPA3-A-N		-505,902			
20	TPA3-A-N2		-2,637			
21	TPA3-A-NEM $		-2,138			
22	TPA3-A-P	1,229	97,059	2	614,500	0.0790
23	TPA3-A-P @	2,139	142,019	1	2,139,000	0.0664
24	TPA3-A-P-API	1,659	154,379	1	1,659,000	0.0931
25	TPA3-A-P-API@	27	23,898	1	27,000	0.8851
26	TPA3-A-P-N	5,648	587,034	2	2,824,000	0.1039
27	TPA3-A-S	68,958	8,533,713	116	594,466	0.1238
28	TPA3-A-S @	5,457	414,739	8	682,125	0.0760
29	TPA3-A-S-API	8,886	883,922	15	592,400	0.0995
30	TPA3-A-S-API@	759	68,320	1	759,000	0.0900
31	TPA3-A-S-API$	443	40,344	1	443,000	0.0911
32	TPA3-A-S-N	87,149	7,587,737	66	1,320,439	0.0871
33	TPA3-A-S-N $	3,611	190,337	3	1,203,667	0.0527
34	TPA3-A-S-N1 @	811	60,452	1	811,000	0.0745
35	TPA3-A-S-N2	957	88,665	3	319,000	0.0926
36	TPA3-A-S-N2 $	1,208	77,035	2	604,000	0.0638
37	TPA3-A-STDBY	475	44,251	1	475,000	0.0932
38	TPA3-B-CPP-S	4,422	500,230			0.1131
39	TPA3-B-DL #		31,224			
40	TPA3-B-NEM		-6,518			
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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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-B-NEM-P	1,094	142,947	1	1,094,000	0.1307
3	TPA3-B-NEM-S	2,353	220,615	3	784,333	0.0938
4	TPA3-B-NEM-S$	5,209	353,767	1	5,209,000	0.0679
5	TPA3-B-P	2,854	248,981	2	1,427,000	0.0872
6	TPA3-B-S	8,183	957,759	2	4,091,500	0.1170
7	TPA3-B-S $	-1,824	-111,323	2	-912,000	0.0610
8	TPA3-B-SEC	29,486	2,609,776	20	1,474,300	0.0885
9	TPA3D-5T8	24,751	2,849,456	21	1,178,619	0.1151
10	TPA3D-5T8 $	2,396	171,323	1	2,396,000	0.0715
11	TPA3D-5T8-API	1,286	136,831	1	1,286,000	0.1064
12	TPA3-D-RTP	548	64,344	1	548,000	0.1174
13	TPA3E-5T8	58,674	7,280,100	55	1,066,800	0.1241
14	TPA3E-5T8 @	1,958	166,420	3	652,667	0.0850
15	TPA3E-5T8 $	287	23,767			0.0828
16	TPA3E-5T8-API	41	8,707			0.2124
17	TPA3E-5T8API$	235	22,958	1	235,000	0.0977
18	T-PA3EAPIN1S	-332	-23,476			0.0707
19	T-PA3EAPIN2S	1,342	184,287	4	335,500	0.1373
20	T-PA3E-APIS	5,601	698,653	11	509,182	0.1247
21	T-PA3E-APIS $	542	41,384	1	542,000	0.0764
22	TPA3-SOP2 @		8,551			
23	TU8B-APSE-N2P	2,076	268,321	3	692,000	0.1292
24	TU8B-APSE-N2S	655	71,091	1	655,000	0.1085
25	TU8B-APSE-N-S	1,990	318,323	2	995,000	0.1600
26	TU8B-APSE-N-T	115,770	11,661,622	1	115,770,000	0.1007
27	TU8B-APSE-P @	-1,288	-99,671			0.0774
28	TU8B-APSE-S	996	154,538	1	996,000	0.1552
29	TU8B-APSE-SN$	631	53,889	1	631,000	0.0854
30	TU8B-CPP-P	24,308	3,146,136	3	8,102,667	0.1294
31	TU8B-CPP-T	9,803	1,149,600	2	4,901,500	0.1173
32	TU8B-P	40,010	4,634,037	5	8,002,000	0.1158
33	TU8B-P @	55,708	3,461,491	6	9,284,667	0.0621
34	TU8B-P-BIP	13,401	1,642,656	1	13,401,000	0.1226
35	TU8B-P-BIP @	16,956	819,547	1	16,956,000	0.0483
36	TU8B-P-BIP-N	-2,087	-216,123			0.1036
37	TU8B-P-BIP-N@	24,232	990,529	1	24,232,000	0.0409
38	TU8B-P-CPPN1	18,385	2,418,378	3	6,128,333	0.1315
39	TU8B-P-CPPN2	970	150,426	1	970,000	0.1551
40	TU8B-P-N	144,017	18,207,443	13	11,078,231	0.1264
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
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1	ACCOUNT 442 CONTINUED					
2	TU8B-P-N @	26,478	2,011,667	4	6,619,500	0.0760
3	TU8B-P-N2	-3,901	-643,047			0.1648
4	TU8B-S	36,404	4,612,615	15	2,426,933	0.1267
5	TU8B-S @	29,354	2,217,842	5	5,870,800	0.0756
6	TU8B-S-BIP @	6,675	675,384	1	6,675,000	0.1012
7	TU8B-S-BIP-N	15,078	1,841,847	2	7,539,000	0.1222
8	TU8B-S-BIP-N@	15,087	846,766	3	5,029,000	0.0561
9	TU8B-S-BIP-N$	8,012	677,698	2	4,006,000	0.0846
10	TU8B-S-BIP-N2	7,195	582,668	1	7,195,000	0.0810
11	TU8B-S-CPPN1	30,722	4,603,187	9	3,413,556	0.1498
12	TU8B-S-CPPN2	2,746	386,257	3	915,333	0.1407
13	TU8B-S-N	56,377	7,878,065	21	2,684,619	0.1397
14	TU8B-S-N @	99,441	7,723,263	28	3,551,464	0.0777
15	TU8B-S-N2	10,357	1,448,630	4	2,589,250	0.1399
16	TU8B-S-N2 @	7,985	811,934	4	1,996,250	0.1017
17	TU8B-T	8,802	693,436			0.0788
18	TU8B-T @	119,814	3,079,142	2	59,907,000	0.0257
19	TU8B-T-BIP-N	49,885	4,479,805	1	49,885,000	0.0898
20	TU8B-T-CPPN1	53,041	4,807,020	1	53,041,000	0.0906
21	TU8B-T-N	243,045	21,770,371	5	48,609,000	0.0896
22	TU8-N2-S $	2,116	197,581	1	2,116,000	0.0934
23	TU8R-APSE-N2P	1,035	93,273	2	517,500	0.0901
24	TU8R-APSE-N2S	3,222	351,964	4	805,500	0.1092
25	TU8RAPSE-N2S@	629	34,900	1	629,000	0.0555
26	TU8R-APSE-N-P	4,102	416,188	3	1,367,333	0.1015
27	TU8RAPSE-N-P@	1,710	139,247	1	1,710,000	0.0814
28	TU8RAPSEN-P $	3,325	229,921	3	1,108,333	0.0691
29	TU8R-APSE-N-S	11,183	1,061,252	11	1,016,636	0.0949
30	TU8RAPSE-N-S@	789	55,414	1	789,000	0.0702
31	TU8RAPSEN-S $	3,138	219,160	3	1,046,000	0.0698
32	TUG3AAPSE-N2S	18	3,011			0.1673
33	TUG3BAPSE-N2P	76	10,262			0.1350
34	TUG3BAPSE-N2S	847	164,733	3	282,333	0.1945
35	TUG3BAPSEN2S@	512	52,606	1	512,000	0.1027
36	TUG3BAPSE-N-S	1,821	247,583	3	607,000	0.1360
37	TUG3BAPSEN-S@	684	63,927	1	684,000	0.0935
38	TUG3BAPSEN-S$	2,509	248,240	5	501,800	0.0989
39	TUG3BAPSE-S-S	117	55,403	1	117,000	0.4735
40	TUGS3-B-S-DL#		60,569			
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
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1	ACCOUNT 442 CONTINUED					
2	WIRETECHRATE	7,944	1,415,546			0.1782
3						
4	OTHER ADJUSTMENTS		-5,919,002			
5						
6	TOTAL ACCOUNT 442	50,558,863	6,172,905,731	634,174	79,724	0.1221
7						
8						
9	ACCOUNT 444					
10						
11	AL-2-F	419	34,108	27	15,519	0.0814
12	AL-2-F $	75	2,730	2	37,500	0.0364
13	GS-1	6	2,031	2	3,000	0.3385
14	LS-1-ALLNITE	131,744	51,187,096	2,993	44,017	0.3885
15	LS1-ALLNITE@	452	59,751	6	75,333	0.1322
16	LS1-ALLNITE$	63,790	14,803,581	587	108,671	0.2321
17	LS-2	70,391	8,511,607	3,659	19,238	0.1209
18	LS-2 @	2,315	331,185	66	35,076	0.1431
19	LS-2 $	11,920	1,132,726	375	31,787	0.0950
20	LS-2-B	49,635	9,624,152	184	269,755	0.1939
21	LS-2-B $	6,148	916,898	161	38,186	0.1491
22	LS-3	35,101	3,203,712	5,045	6,958	0.0913
23	LS-3 @	4,186	176,567	631	6,634	0.0422
24	LS-3 $	3,777	253,046	713	5,297	0.0670
25	LS-3-B	-1	142	1	-1,000	-0.1420
26	LS-3-B $	-1	-93			0.0930
27	OL-1-ALLNITE	3	756	2	1,500	0.2520
28	TC-1	6,102	1,191,224	1,650	3,698	0.1952
29	TC-1 @	88	10,640	21	4,190	0.1209
30	TC-1 $	1,411	204,991	431	3,274	0.1453
31	TGS1-A	10	1,865			0.1865
32	TGS1-A-N	9	1,592	1	9,000	0.1769
33	TGS1-B @		108			
34	TOU-8-D-P	32,536	3,798,186	1	32,536,000	0.1167
35	TOU-GS1D	479	68,890	49	9,776	0.1438
36	TOU-GS1D @	14	1,552	3	4,667	0.1109
37	TOU-GS1D $	72	5,959	7	10,286	0.0828
38	TOU-GS1E	1,610	307,616	260	6,192	0.1911
39	TOU-GS1E @	43	4,654	9	4,778	0.1082
40	TOU-GS1E $	469	56,918	87	5,391	0.1214
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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	04/14/2021	End of 2020/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	TOU-GS1E-CPP	914	185,331	224	4,080	0.2028
3	TOU-GS2D	1,340	200,828	4	335,000	0.1499
4	TOU-GS2D $	112	14,606	2	56,000	0.1304
5	TOU-GS2D-CPP	351	63,271	3	117,000	0.1803
6						
7	OTHER ADJUSTMENTS		-175,760			
8						
9	TOTAL ACCOUNT 444	425,520	96,182,466	17,206	24,731	0.2260
10						
11	ACCOUNT 445					
12						
13	EDWARDS-AFB		-15,654			
14						
15	OTHER ADJUSTMENTS		-17,215			
16						
17	TOTAL ACCOUNT 445		-32,869			
18						
19	ACCOUNT 446					
20						
21	LS-3	11	1,305	5	2,200	0.1186
22	TC-1	47	9,443	14	3,357	0.2009
23	TC-1 @	21	2,398	2	10,500	0.1142
24	TC-1 $	1	459	2	500	0.4590
25	TGS1-A @		72			
26	TGS1-B @		671			
27	TOU-8-D-CPP-P	18,498	2,701,018	7	2,642,571	0.1460
28	TOU-8-D-P	6,267	891,007	3	2,089,000	0.1422
29	TOU-8-D-PRI @	10,511	802,613	1	10,511,000	0.0764
30	TOU-8-D-PRI $	12,300	1,207,476	8	1,537,500	0.0982
31	TOU-GS1D	205	30,060	6	34,167	0.1466
32	TOU-GS1D @	121	11,303	16	7,563	0.0934
33	TOU-GS1E	107	20,012	9	11,889	0.1870
34	TOU-GS1E @	19	2,426	3	6,333	0.1277
35	TOU-GS1E $	141	15,208	12	11,750	0.1079
36	TOU-GS1E-CPP	63	13,527	17	3,706	0.2147
37	TOU-GS2D $	585	64,852	3	195,000	0.1109
38	TOU-GS2D-CPP	243	50,023	1	243,000	0.2059
39	TOU-GS3D-CP-P	8,132	1,387,205	9	903,556	0.1706
40	TOU-GS3-D-P	3,386	555,515	4	846,500	0.1641
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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	TOU-GS3-D-P $	6,001	642,971	7	857,286	0.1071
3	TOU-GS3-D-S $	2,112	147,149	1	2,112,000	0.0697
4	TOU-GS3-E-P	2,377	406,712	4	594,250	0.1711
5	TOU-GS3-EP $	142	9,295			0.0655
6	TU8B-P @		49,397			
7						
8	OTHER ADJUSTMENTS			-1		
9						
10	TOTAL ACCOUNT 446	71,290	9,022,117	133	536,015	0.1266
11						
12						
13						
14	ACCOUNT 448					
15						
16	GS-1-SCE	30	5,598	5	6,000	0.1866
17	GS-2-SCE	194	39,433	1	194,000	0.2033
18	PA-1-SCE	90	18,931	10	9,000	0.2103
19	PA-2-SCE	705	93,637	7	100,714	0.1328
20	TOU-GS2D-SCE	890	111,546	1	890,000	0.1253
21						
22	OTHER ADJUSTMENTS					
23						
24	TOTAL ACCOUNT 448	1,909	269,145	24	79,542	0.1410
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	83,532,663	11,637,828,445	5,168,403	16,162	0.1393
42	Total Unbilled Rev.(See Instr. 6)	-25,030	33,333,000	0	0	-1.3317
43	TOTAL	83,507,633	11,671,161,445	5,168,403	16,157	0.1398

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.

2017 FERC Form 1 - Page 304 FOOTNOTE Legend & Instruction #5 Data

FOOTNOTES:

A = Southern California Edison Company revenue only. Does not reflect Department of Water Resources (DWR) portion that is billed and remitted to DWR. Thus, the Revenue per KWh may not reflect the customers' full rate.
B = Data reflected under parent rate schedule or other applicable tariff.
C = Less than 1 MWh.
D = Less than 12 months' data.

OTHER ADJUSTMENTS

OTHER ADJUSTMENTS may include Misc Transactions Used for Billing Purposes, rounding, and/or other miscellaneous adjustments.

FOR INSTRUCTION 5:

ESTIMATED REVENUE DERIVED FROM FUEL COST ADJUSTMENT

440	RESIDENTIAL SALES	$0
442	AGRICULTURAL, COMMERCIAL & INDUSTRIAL SALES	$0
444	PUBLIC STREET & HIGHWAY LIGHTING	$0
445	OTHER SALES TO PUBLIC AUTHORITIES	$0
446	RAILROADS	$0
448	INTERDEPARTMENTAL	$0
	TOTAL SALES TO ULTIMATE CONSUMERS	$0
447	SALES FOR RESALE & FRINGE	$0
	TOTAL SALES	$0

Schedule Page: 304 Line No.: 34 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 34 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 34 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 40 Column: b

Less than 1 MWh.

Schedule Page: 304.1 Line No.: 7 Column: b

Less than 1 MWh.

Schedule Page: 304.1 Line No.: 8 Column: b

Less than 1 MWh.

Name of Respondent Southern California Edison Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 37 Column: b
Less than 1 MWh.
Schedule Page: 304.2 Line No.: 16 Column: b
Less than 1 MWh.
Schedule Page: 304.3 Line No.: 16 Column: b
Less than 1 MWh.
Schedule Page: 304.4 Line No.: 10 Column: b
Less than 1 MWh.
Schedule Page: 304.5 Line No.: 10 Column: b
Less than 1 MWh.
Schedule Page: 304.5 Line No.: 19 Column: b
Less than 1 MWh.
Schedule Page: 304.7 Line No.: 31 Column: b
Less than 1 MWh.
Schedule Page: 304.10 Line No.: 5 Column: b
Less than 1 MWh.
Schedule Page: 304.10 Line No.: 15 Column: b
Less than 1 MWh.
Schedule Page: 304.13 Line No.: 8 Column: b
Less than 1 MWh.
Schedule Page: 304.14 Line No.: 11 Column: b
Less than 1 MWh.
Schedule Page: 304.14 Line No.: 23 Column: b
Less than 1 MWh.
Schedule Page: 304.14 Line No.: 36 Column: b
Less than 1 MWh.
Schedule Page: 304.14 Line No.: 39 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.
Schedule Page: 304.15 Line No.: 4 Column: b
Less than 1 MWh.
Schedule Page: 304.15 Line No.: 17 Column: b
Less than 1 MWh.
Schedule Page: 304.15 Line No.: 22 Column: b
Less than 1 MWh.
Schedule Page: 304.16 Line No.: 3 Column: b
Less than 1 MWh.
Schedule Page: 304.16 Line No.: 5 Column: b
Less than 1 MWh.
Schedule Page: 304.16 Line No.: 14 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.16 Line No.: 14 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.16 Line No.: 14 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.16 Line No.: 17 Column: b
Less than 1 MWh.
Schedule Page: 304.16 Line No.: 28 Column: b
Less than 1 MWh.
Schedule Page: 304.17 Line No.: 3 Column: b
Less than 1 MWh.
Schedule Page: 304.17 Line No.: 5 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 5 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 5 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 37 Column: b

Less than 1 MWh.

Schedule Page: 304.17 Line No.: 38 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 38 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 38 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.18 Line No.: 4 Column: b

Less than 1 MWh.

Schedule Page: 304.18 Line No.: 18 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.18 Line No.: 18 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.18 Line No.: 18 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.19 Line No.: 23 Column: b

Less than 1 MWh.

Schedule Page: 304.20 Line No.: 18 Column: b

Less than 1 MWh.

Schedule Page: 304.21 Line No.: 2 Column: b

Less than 1 MWh.

Schedule Page: 304.21 Line No.: 8 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 8 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 8 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 11 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 11 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 11 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.21 Line No.: 16 Column: b

Less than 1 MWh.

Schedule Page: 304.21 Line No.: 17 Column: b

Less than 1 MWh.

Schedule Page: 304.21 Line No.: 32 Column: b

Less than 1 MWh.

Schedule Page: 304.22 Line No.: 7 Column: b

Less than 1 MWh.

Schedule Page: 304.23 Line No.: 21 Column: b

Less than 1 MWh.

Schedule Page: 304.24 Line No.: 15 Column: b

Less than 1 MWh.

Schedule Page: 304.25 Line No.: 25 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.25 Line No.: 25 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.25 Line No.: 25 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.25 Line No.: 36 Column: b
Less than 1 MWh.
Schedule Page: 304.25 Line No.: 37 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 8 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 9 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 10 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 11 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 12 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 28 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 31 Column: b
Less than 1 MWh.
Schedule Page: 304.26 Line No.: 40 Column: b
Less than 1 MWh.
Schedule Page: 304.27 Line No.: 34 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.27 Line No.: 34 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.27 Line No.: 34 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.28 Line No.: 19 Column: b
Less than 1 MWh.
Schedule Page: 304.28 Line No.: 20 Column: b
Less than 1 MWh.
Schedule Page: 304.28 Line No.: 34 Column: b
Less than 1 MWh.
Schedule Page: 304.28 Line No.: 35 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 8 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 9 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 26 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 27 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 28 Column: b
Less than 1 MWh.
Schedule Page: 304.29 Line No.: 29 Column: b

Less than 1 MWh.

Schedule Page: 304.29 Line No.: 31 Column: b

Less than 1 MWh.

Schedule Page: 304.29 Line No.: 35 Column: b

Less than 1 MWh.

Schedule Page: 304.29 Line No.: 36 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.29 Line No.: 36 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.29 Line No.: 36 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.29 Line No.: 37 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 2 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 21 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 31 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 32 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 34 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 38 Column: b

Less than 1 MWh.

Schedule Page: 304.30 Line No.: 39 Column: b

Less than 1 MWh.

Schedule Page: 304.31 Line No.: 22 Column: b

Less than 1 MWh.

Schedule Page: 304.31 Line No.: 24 Column: b

Less than 1 MWh.

Schedule Page: 304.31 Line No.: 26 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.31 Line No.: 26 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.31 Line No.: 26 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.31 Line No.: 27 Column: b

Less than 1 MWh.

Schedule Page: 304.31 Line No.: 28 Column: b

Less than 1 MWh.

Schedule Page: 304.31 Line No.: 30 Column: b

Less than 1 MWh.

Schedule Page: 304.32 Line No.: 18 Column: b

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.32 Line No.: 18 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.32 Line No.: 18 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.32 Line No.: 19 Column: b

Less than 1 MWh.

Schedule Page: 304.32 Line No.: 20 Column: b
Less than 1 MWh.
Schedule Page: 304.32 Line No.: 21 Column: b
Less than 1 MWh.
Schedule Page: 304.32 Line No.: 39 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.32 Line No.: 39 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.32 Line No.: 39 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.32 Line No.: 40 Column: b
Less than 1 MWh.
Schedule Page: 304.33 Line No.: 22 Column: b
Less than 1 MWh.
Schedule Page: 304.34 Line No.: 40 Column: b
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.34 Line No.: 40 Column: d
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.34 Line No.: 40 Column: e
Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.35 Line No.: 4 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.
Schedule Page: 304.35 Line No.: 33 Column: b
Less than 1 MWh.
Schedule Page: 304.36 Line No.: 7 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.
Schedule Page: 304.36 Line No.: 13 Column: b
Less than 1 MWh.
Schedule Page: 304.36 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: 304.36 Line No.: 25 Column: b
Less than 1 MWh.
Schedule Page: 304.36 Line No.: 26 Column: b
Less than 1 MWh.
Schedule Page: 304.37 Line No.: 6 Column: b
Less than 1 MWh.
Schedule Page: 304.37 Line No.: 8 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.
Schedule Page: 304.37 Line No.: 22 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) (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	California Independent System Operator		1	N/A	N/A	N/A
2	3 Phases Renewables Inc.	OS	1	N/A	N/A	N/A
3	Avangrid Renewables, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
4	BP Energy Company	SF	FERC VOL. 8	N/A	N/A	N/A
5	Brookfield Renewable Trading & Market	SF	1	N/A	N/A	N/A
6	Calpine Energy Services LP	SF	FERC VOL. 8	N/A	N/A	N/A
7	Central Coast Community Energy	SF	1	N/A	N/A	N/A
8	Citigroup Energy Inc	SF	FERC VOL. 8	N/A	N/A	N/A
9	City & County SF through its PUC, Clean	OS	1	N/A	N/A	N/A
10	City of Rancho Cucamonga	SF	1	N/A	N/A	N/A
11	City of San Jose	OS	1	N/A	N/A	N/A
12	City of Vernon	SF	1	N/A	N/A	N/A
13	Clean Power Alliance of So. California	OS	1	N/A	N/A	N/A
14	Commercial Energy of Montana, Inc.	OS	1	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	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	Desert Community Energy	OS	1	N/A	N/A	N/A
2	Direct Energy Business Marketing, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
3	East Bay Community Energy Authority	OS	1	N/A	N/A	N/A
4	EDF Trading North America, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
5	Exelon Generation Company, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
6	Macquarie Energy LLC	SF	FERC VOL. 8	N/A	N/A	N/A
7	Macquarie Futures USA Inc. (Clearing)	OS	1	N/A	N/A	N/A
8	Marin Clean Energy	OS	1	N/A	N/A	N/A
9	Morgan Stanley Capital Group Inc.	SF	FERC VOL. 8	N/A	N/A	N/A
10	Nextera Energy Power Marketing, LLC	SF	WSPP-2	N/A	N/A	N/A
11	Pacific Gas & Electric Company-Pipeline	SF	WSPP-2	N/A	N/A	N/A
12	Peninsula Clean Energy Authority	SF	1	N/A	N/A	N/A
13	San Diego Gas & Electric Company	SF	WSPP-2	N/A	N/A	N/A
14	Sempra Gas & Marketing LLC	SF	FERC VOL. 8	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Shell Energy North America (US), L.P.	SF	FERC VOL. 8	N/A	N/A	N/A
2	Silicon Valley Clean Energy Authority	OS	1	N/A	N/A	N/A
3	Sonoma Clean Power Authority	SF	1	N/A	N/A	N/A
4	Srectrade Inc.	OS	1	N/A	N/A	N/A
5	Tenaska Pwer Services Company	SF	WSPP	N/A	N/A	N/A
6	The Energy Authority, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
7	Western Community Energy	OS	1	N/A	N/A	N/A
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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.
2,508,668		47,156,723		47,156,723	1
	22,000			22,000	2
75		1,050		1,050	3
271		10,298		10,298	4
75		4,125		4,125	5
	6,270,078			6,270,078	6
	2,260,870			2,260,870	7
31,730		1,872,583		1,872,583	8
	1,866,070		10,524,000	12,390,070	9
	12,000			12,000	10
	7,573,935		8,100,000	15,673,935	11
	2,050,000			2,050,000	12
	9,043,523		38,334,472	47,377,995	13
			877,100	877,100	14
0	0	0	0	0	
4,185,296	78,055,918	71,647,953	92,060,452	241,764,323	
4,185,296	**78,055,918**	**71,647,953**	**92,060,452**	**241,764,323**	

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	04/14/2021	End of 2020/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.
	4,040,917			4,040,917	1
	938,750		2,588,800	3,527,550	2
	7,817,902		6,330,000	14,147,902	3
72		2,421	1,120,000	1,122,421	4
500	936,332	122,000		1,058,332	5
2,072		76,878		76,878	6
375		26,025		26,025	7
	2,494,239		9,508,450	12,002,689	8
161,256		2,560,007		2,560,007	9
	216,000			216,000	10
	8,227,350			8,227,350	11
	7,557,751			7,557,751	12
	212,150			212,150	13
	603,859			603,859	14
0	0	0	0	0	
4,185,296	78,055,918	71,647,953	92,060,452	241,764,323	
4,185,296	**78,055,918**	**71,647,953**	**92,060,452**	**241,764,323**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,480,202	493,600	19,815,843	4,150,000	24,459,443	1
	131,250		8,547,000	8,678,250	2
	1,301,655			1,301,655	3
			181,130	181,130	4
	292,017			292,017	5
	824,800		1,799,500	2,624,300	6
	12,868,870			12,868,870	7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,185,296	78,055,918	71,647,953	92,060,452	241,764,323	
4,185,296	**78,055,918**	**71,647,953**	**92,060,452**	**241,764,323**	

Schedule Page: 310 Line No.: 1 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 2 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310 Line No.: 2 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 5 Column: a
Brookfield Renewable Trading & Marketing
Schedule Page: 310 Line No.: 5 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 7 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 9 Column: a
City & County of SF through its PUC, CleanPowerSF
Schedule Page: 310 Line No.: 9 Column: b
OS 15 - LOW CARBON FUEL STANDARD (SALES) AND REC (SALES)
Schedule Page: 310 Line No.: 9 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 9 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310 Line No.: 10 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 11 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310 Line No.: 11 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 11 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310 Line No.: 12 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 13 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310 Line No.: 13 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310 Line No.: 13 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310 Line No.: 14 Column: b
OS 15 - LOW CARBON FUEL STANDARD (SALES) AND REC (SALES)

Schedule Page: 310 Line No.: 14 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).

Schedule Page: 310 Line No.: 14 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.1 Line No.: 1 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310.1 Line No.: 1 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.1 Line No.: 2 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.1 Line No.: 3 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310.1 Line No.: 3 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.1 Line No.: 3 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.1 Line No.: 4 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.1 Line No.: 7 Column: b
OS 13 - BROKERS
Schedule Page: 310.1 Line No.: 7 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.1 Line No.: 8 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310.1 Line No.: 8 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.1 Line No.: 8 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.1 Line No.: 12 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.2 Line No.: 1 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.2 Line No.: 2 Column: b
OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE
Schedule Page: 310.2 Line No.: 2 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.2 Line No.: 2 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).
Schedule Page: 310.2 Line No.: 3 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.2 Line No.: 4 Column: b
OS 15 - LOW CARBON FUEL STANDARD (SALES) AND REC (SALES)
Schedule Page: 310.2 Line No.: 4 Column: c
1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).
Schedule Page: 310.2 Line No.: 4 Column: j
Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).

Schedule Page: 310.2 Line No.: 6 Column: j

Other Charges is revenue received from the sale of Renewable Energy Credits (RECs).

Schedule Page: 310.2 Line No.: 7 Column: b

OS 14 - RA, ENERGY STORAGE, DEMAND RESPONSE

Schedule Page: 310.2 Line No.: 7 Column: c

1 - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	4,539	1,598
5	(501) Fuel		-677
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	178,514	98,280
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	183,053	99,201
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	137,829	101,844
16	(511) Maintenance of Structures		69
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	137,829	101,913
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	320,882	201,114
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	17,263,716	16,636,051
25	(518) Fuel	30,990,585	41,253,987
26	(519) Coolants and Water	7,649,530	7,363,344
27	(520) Steam Expenses	4,314,547	4,710,057
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	6,355,330	6,226,925
31	(524) Miscellaneous Nuclear Power Expenses	26,612,564	28,109,812
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	93,186,272	104,300,176
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,515,600	2,739,123
36	(529) Maintenance of Structures	1,234,813	1,227,638
37	(530) Maintenance of Reactor Plant Equipment	6,389,932	6,884,342
38	(531) Maintenance of Electric Plant	5,718,055	6,195,856
39	(532) Maintenance of Miscellaneous Nuclear Plant	1,857,398	1,824,746
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	17,715,798	18,871,705
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	110,902,070	123,171,881
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	3,016,824	1,792,892
45	(536) Water for Power	3,824,872	4,198,547
46	(537) Hydraulic Expenses	2,890,289	2,535,428
47	(538) Electric Expenses	1,674,274	1,854,341
48	(539) Miscellaneous Hydraulic Power Generation Expenses	23,791,142	20,882,787
49	(540) Rents	1,276,108	1,259,308
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	36,473,509	32,523,303
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	4,861,685	4,877,646
54	(542) Maintenance of Structures	3,026,623	679,495
55	(543) Maintenance of Reservoirs, Dams, and Waterways	7,851,025	2,145,558
56	(544) Maintenance of Electric Plant	3,486,574	5,076,970
57	(545) Maintenance of Miscellaneous Hydraulic Plant	901,142	2,492,059
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	20,127,049	15,271,728
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	56,600,558	47,795,031

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	04/14/2021	End of 2020/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	3,683,674	1,980,242
63	(547) Fuel	88,326,227	117,593,473
64	(548) Generation Expenses	7,797,457	3,256,135
65	(549) Miscellaneous Other Power Generation Expenses	46,210,144	45,632,382
66	(550) Rents	2,457,092	2,793,602
67	TOTAL Operation (Enter Total of lines 62 thru 66)	148,474,594	171,255,834
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	3,253,918	2,815,311
70	(552) Maintenance of Structures	1,715,379	1,599,030
71	(553) Maintenance of Generating and Electric Plant	14,631,031	13,681,708
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,810,079	2,104,819
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	21,410,407	20,200,868
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	169,885,001	191,456,702
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,629,307,219	4,583,716,123
77	(556) System Control and Load Dispatching	957,699	987,444
78	(557) Other Expenses	36,367,786	32,295,238
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,666,632,704	4,616,998,805
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,004,341,215	4,979,623,533
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,972,046	8,310,973
84			
85	(561.1) Load Dispatch-Reliability	279,388	136,381
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	12,950,193	10,843,397
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	20,997,389	30,864,993
89	(561.5) Reliability, Planning and Standards Development	4,828,526	4,579,897
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	9,729,818	
93	(562) Station Expenses	33,294,535	22,482,225
94	(563) Overhead Lines Expenses	40,209,181	38,009,999
95	(564) Underground Lines Expenses	2,410,542	1,975,667
96	(565) Transmission of Electricity by Others	20,988,646	19,935,808
97	(566) Miscellaneous Transmission Expenses	220,141,515	163,563,935
98	(567) Rents	18,947,630	17,162,141
99	TOTAL Operation (Enter Total of lines 83 thru 98)	393,749,409	317,865,416
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,168,981	2,698,423
102	(569) Maintenance of Structures	2,449,526	402,467
103	(569.1) Maintenance of Computer Hardware	4,964,119	5,269,133
104	(569.2) Maintenance of Computer Software	22,182,791	21,852,872
105	(569.3) Maintenance of Communication Equipment	11,959,667	15,140,177
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	9,351,887	7,563,220
108	(571) Maintenance of Overhead Lines	86,816,322	84,245,475
109	(572) Maintenance of Underground Lines	467,023	1,160,927
110	(573) Maintenance of Miscellaneous Transmission Plant	1,583,991	2,238,849
111	TOTAL Maintenance (Total of lines 101 thru 110)	141,944,307	140,571,543
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	535,693,716	458,436,959

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	04/14/2021	End of 2020/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	12,953,142	13,255,506
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	12,953,142	13,255,506
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)	12,953,142	13,255,506
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	10,353,014	12,655,176
135	(581) Load Dispatching		
136	(582) Station Expenses	36,714,424	34,054,379
137	(583) Overhead Line Expenses	138,125,662	146,803,169
138	(584) Underground Line Expenses	9,293,166	8,685,086
139	(585) Street Lighting and Signal System Expenses	472,812	420,823
140	(586) Meter Expenses	20,815,168	21,631,720
141	(587) Customer Installations Expenses	23,399,098	21,189,487
142	(588) Miscellaneous Expenses	119,972,456	119,577,992
143	(589) Rents	2,753,276	2,524,010
144	TOTAL Operation (Enter Total of lines 134 thru 143)	361,899,076	367,541,842
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,791,821	2,484,195
147	(591) Maintenance of Structures	163,472	71,779
148	(592) Maintenance of Station Equipment	8,090,409	7,317,361
149	(593) Maintenance of Overhead Lines	548,069,557	531,640,944
150	(594) Maintenance of Underground Lines	50,692,390	53,366,942
151	(595) Maintenance of Line Transformers	4,395,060	4,325,830
152	(596) Maintenance of Street Lighting and Signal Systems	4,463,402	6,382,821
153	(597) Maintenance of Meters	5,610,755	5,498,585
154	(598) Maintenance of Miscellaneous Distribution Plant	209,266,180	-7,554,179
155	TOTAL Maintenance (Total of lines 146 thru 154)	832,543,046	603,534,278
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	1,194,442,122	971,076,120
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	19,622,294	18,638,793
160	(902) Meter Reading Expenses	2,808,426	2,345,080
161	(903) Customer Records and Collection Expenses	107,675,241	104,173,929
162	(904) Uncollectible Accounts	157,119,435	20,311,565
163	(905) Miscellaneous Customer Accounts Expenses	1,791,686	2,111,555
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	289,017,082	147,580,922

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	5,083,176	2,881,540
168	(908) Customer Assistance Expenses	386,037,860	439,998,092
169	(909) Informational and Instructional Expenses	16,076,390	18,812,156
170	(910) Miscellaneous Customer Service and Informational Expenses	63	1,504
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	407,197,489	461,693,292
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,801,292	4,811,999
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	4,801,292	4,811,999
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	512,818,190	413,850,310
182	(921) Office Supplies and Expenses	259,355,778	250,234,425
183	(Less) (922) Administrative Expenses Transferred-Credit	223,403,958	225,318,190
184	(923) Outside Services Employed	49,255,741	59,887,693
185	(924) Property Insurance	20,441,370	15,607,270
186	(925) Injuries and Damages	2,255,479,067	902,073,996
187	(926) Employee Pensions and Benefits	78,787,907	82,906,034
188	(927) Franchise Requirements	113,495,974	104,335,318
189	(928) Regulatory Commission Expenses	11,842,729	11,713,250
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	14,923,247	11,245,961
192	(930.2) Miscellaneous General Expenses	38,904,934	14,071,912
193	(931) Rents	9,432,312	8,581,490
194	TOTAL Operation (Enter Total of lines 181 thru 193)	3,141,333,291	1,649,189,469
195	Maintenance		
196	(935) Maintenance of General Plant	22,574,402	26,158,179
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	3,163,907,693	1,675,347,648
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	10,612,353,751	8,711,825,979

Schedule Page: 320 Line No.: 64 Column: b

Account 548 - Includes $73,766 of energy storage costs related to Mira Loma.

Schedule Page: 320 Line No.: 64 Column: c

Account 548 - Includes $247,701 of energy storage costs related to Mira Loma.

Schedule Page: 320 Line No.: 71 Column: b

Account 553 - Includes $619,625 of energy storage costs related to Mira Loma, Center and Grapeland.

Schedule Page: 320 Line No.: 71 Column: c

Account 553 - Includes $949,993 of energy storage costs related to Mira Loma, Center and Grapeland.

Schedule Page: 320 Line No.: 76 Column: b

Account 555 - Includes $266,050 of energy storage costs related to Tesla Battey A and B.

Schedule Page: 320 Line No.: 76 Column: c

Account 555 - Includes $112,500 of energy storage costs related to Tesla Battery A and B.

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.

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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	COOPERATIVES:					
2	VALLEY ELECTRIC	RQ	218	NA	NA	NA
3	GHG IMPORT:					
4	CALIFORNIA AIR RESOURCE BOARD	OS	MBRA	NA	NA	NA
5	MUNICIPALITIES:					
6	ANAHEIM, CITY OF FRINGE	OS	MBRA	NA	NA	NA
7	BANNING, CITY OF FRINGE	OS	MBRA	NA	NA	NA
8	LA DEPT OF WTR & PWR FRINGE	OS	MBRA	NA	NA	NA
9	RIVERSIDE, CITY OF FRINGE	OS	MBRA	NA	NA	NA
10	BROKERS/OTHER:					
11	BGC FINANCIAL, LP	OS	MBRA	NA	NA	NA
12	CHOICE NATURAL GAS, LP	OS	MBRA	NA	NA	NA
13	CHOICE POWER, LP	OS	MBRA	NA	NA	NA
14	EQUUS ENERGY GROUP, LLC	OS	MBRA	NA	NA	NA
	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) (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	EVOLUTION MARKETS FUTURES LLC	OS	MBRA	NA	NA	NA
2	EVOLUTION MARKETS INC.	OS	MBRA	NA	NA	NA
3	ICAP ENERGY LLC	OS	MBRA	NA	NA	NA
4	INTERCONTINENTAL EXCHANGE	OS	MBRA	NA	NA	NA
5	JPMORGAN CHASE BANK N.A.	OS	MBRA	NA	NA	NA
6	MACQUARIE FUTURES USA INC	OS	MBRA	NA	NA	NA
7	TFS ENERGY FUTURES LLC	OS	MBRA	NA	NA	NA
8	TULLETT PREBON AMERICAS CORP.	OS	MBRA	NA	NA	NA
9	GAS:					
10	EL PASO NATURAL GAS CO., L.L.C.	SF	WSPP-2	NA	NA	NA
11	PACIFIC GAS & ELECTRIC	SF	WSPP-2	NA	NA	NA
12	SOUTHERN CALIFORNIA GAS COMPANY	SF	FERC VOL. 8	NA	NA	NA
13	SOUTHERN CALIFORNIA GAS COMPANY -	SF	FERC VOL. 8	NA	NA	NA
14	NON-ASSOCIATED UTILITIES:					
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	NEXTERA ENERGY POWER MARKETING,	SF	WSPP-2	NA	NA	NA
2	PACIFICORP	SF	FERC Vol. 8	NA	NA	NA
3	PORTLAND GENERAL ELECTRIC	SF	FERC Vol. 8	NA	NA	NA
4	PUBLIC SERVICE COMPANY OF	SF	WSPP-2	NA	NA	NA
5	SAN DIEGO GAS & ELECTRIC COMPANY	SF	WSPP-2	NA	NA	NA
6	OTHER PUBLIC AUTHORITIES:					
7	BONNEVILLE POWER AUTHORITIES	SF	WSPP-2	NA	NA	NA
8	LOS ANGELES DEPARTMENT OF WATER	SF	WSPP-2	NA	NA	NA
9	POWEREX CORP.	SF	FERC Vol. 8	NA	NA	NA
10	SALT RIVER PROJECT AGRIC. IMPROVMT	SF	WSPP-2	NA	NA	NA
11	POWER MARKETERS DETAIL:					
12	AES ALAMITOS LLC	IU	FERC VOL. 1	NA	NA	NA
13	AES HUNTINGTON BEACH LLC	IU	FERC VOL. 1	NA	NA	NA
14	ARIZONA ELECTRIC POWER	SF	WSPP	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	AVANGRID RENEWABLES, LLC	SF	FERC Vol. 8	NA	NA	NA
2	AVISTA UTILITIES	LU	WSPP-2	NA	NA	NA
3	BP ENERGY COMPANY	SF	FERC Vol. 8	NA	NA	NA
4	BROOKFIELD ENERGY MARKETING LP	SF	MBRA	NA	NA	NA
5	CALPEAK POWER LLC	OS	MBRA	NA	NA	NA
6	CALPINE ENERGY SERVICES LP	SF	FERC Vol. 8	NA	NA	NA
7	CENTRAL COAST COMMUNITY ENERGY	SF	MBRA	NA	NA	NA
8	CITIGROUP ENERGY INC	SF	FERC Vol. 8	NA	NA	NA
9	CITY & COUNTY OF SF THROUGH ITS	OS	MBRA	NA	NA	NA
10	CITY OF SAN JOSE	OS	MBRA	NA	NA	NA
11	CITY OF VERNON	SF	MBRA	NA	NA	NA
12	CLEAN POWER ALLIANCE OF SO.	OS	MBRA	NA	NA	NA
13	COSO GEOTHERMAL POWER HOLDINGS	OS	MBRA	NA	NA	NA
14	DYNEGY MOSS LANDING LLC	LU	FERC Vol. 8	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power 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	EDF TRADING NORTH AMERICA, LLC	SF	FERC Vol. 8	NA	NA	NA
2	ELK HILLS POWER LLC	SF	FERC Vol. 8	NA	NA	NA
3	ELLWOOD POWER, LLC	OS	MBRA	NA	NA	NA
4	ENEL X NORTH AMERICA, INC.	OS	MBRA	NA	NA	NA
5	ENERWISE GLOBAL TECHNOLOGIES, INC	OS	MBRA	NA	NA	NA
6	ENGIE STORAGE SERVICES NA LLC	OS	MBRA	NA	NA	NA
7	EXELON GENERATION COMPANY, LLC	SF	FERC Vol. 8	NA	NA	NA
8	GENON ENERGY MANAGEMENT, LLC	SF	FERC Vol. 8	NA	NA	NA
9	LEAPFROG POWER, INC	OS	MBRA	NA	NA	NA
10	MACQUARIE ENERGY LLC	SF	FERC Vol. 8	NA	NA	NA
11	MARIN CLEAN ENERGY	OS	MBRA	NA	NA	NA
12	MERCURIA ENERGY AMERICA, INC	SF	FERC Vol. 8	NA	NA	NA
13	MORGAN STANLEY CAPITAL GROUP	SF	FERC Vol. 8	NA	NA	NA
14	NEVADA POWER COMPANY	SF	FERC Vol. 8	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	NRG CURTAILMENT SOLUTIONS, INC	OS	MBRA	NA	NA	NA
2	OHMCONNECT CALIFORNIA, LLC	OS	MBRA	NA	NA	NA
3	ORMOND BEACH POWER, LLC	OS	MBRA	NA	NA	NA
4	PENINSULA CLEAN ENERGY AUTHORITY	SF	MBRA	NA	NA	NA
5	PIONEER COMMUNITY ENERGY	OS	MBRA	NA	NA	NA
6	PPA GRAND JOHANNA LLC	OS	MBRA	NA	NA	NA
7	SEMPRA GAS & POWER MARKETING LLC	SF	FERC Vol. 8	NA	NA	NA
8	SHELL ENERGY NO AMERICA US, L.P.	SF	FERC Vol. 8	NA	NA	NA
9	SONOMA CLEAN POWER AUTHORITY	SF	MBRA	NA	NA	NA
10	STANTON ENERGY RELIABILITY CENTER	OS	MBRA	NA	NA	NA
11	STEM INC.	OS	MBRA	NA	NA	NA
12	TENASKA POWER SERVICES COMPANY	SF	WSPP	NA	NA	NA
13	TESLA INC.	OS	MBRA	NA	NA	NA
14	TRANSALTA ENERGY MARKETING (US)	SF	WSPP-2	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	VESI POMONA ENERGY STORAGE	OS	MBRA	NA	NA	NA
2	VOLTUS INC	OS	MBRA	NA	NA	NA
3	TOLLING UNITS:					
4	AES ALAMITOS ENERGY, LLC	LU	MBRA	NA	NA	NA
5	AES HUNTINGTON BEACH ENERGY, LLC	LU	MBRA	NA	NA	NA
6	BLYTHE ENERGY LLC	LU	FERC Vol. 8	NA	NA	NA
7	CPV SENTINEL, LLC	LU	FERC Vol. 8	NA	NA	NA
8	CSU CHANNEL ISLANDS SITE AUTHORITY	IU	MBRA	NA	NA	NA
9	CXA LA PALOMA LLC	LU	FERC Vol. 8	NA	NA	NA
10	EL SEGUNDO ENERGY CENTER LLC	LU	FERC Vol. 8	NA	NA	NA
11	EL SEGUNDO ENERGY CENTER LLC	AD	FERC Vol. 8	NA	NA	NA
12	NRG LONG BEACH GENERATION LLC	LU	FERC Vol. 8	NA	NA	NA
13	O.L.S. ENERGY - CHINO (TOLL/RA)	LU	MBRA	NA	NA	NA
14	WALNUT CREEK ENERGY LLC	LU	FERC Vol. 8	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	WELLHEAD POWER DELANO	LU	FERC Vol. 8	NA	NA	NA
2	NON ASSOCI:					
3	BUREAU INDIAN AFFAIRS	OS	MBRA	NA	NA	NA
4	NON-UTIL:Q					
5	AMTELOPE VALLEY SOLAR, LLC	OS	MBRA	NA	NA	NA
6	CALIENTE SPRINGS, LLC	OS	MBRA	NA	NA	NA
7	GEYSERS POWER COMPANY, LLC	OS	MBRA	NA	NA	NA
8	GOLDEN SPRINGS DEVELOPMENT CO.,	OS	MBRA	NA	NA	NA
9	LANCASTER WAD B, LLC (REMAT)	OS	MBRA	NA	NA	NA
10	SUNSHINE VALLEY SOLAR LLC	OS	MBRA	NA	NA	NA
11	US TOPCO ENERGY, INC (SOCCER	OS	MBRA	NA	NA	NA
12						
13	NON UTILITIES: QUALIFYING FACILITY					
14	1247_ORGANIC ENERGY SOLUTIONS	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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(Including power exchanges)

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1	1251_TWO FIETS	OS	MBRA	NA	NA	NA
2	1252 CA FUEL CELL 2 LLC	OS	MBRA	NA	NA	NA
3	41MB 8ME LLC	OS	MBRA	NA	NA	NA
4	5814_NORTH ROSAMOND SOLAR	OS	MBRA	NA	NA	NA
5	5892_CED WISTARIA SOLAR	OS	MBRA	NA	NA	NA
6	67RK 8ME, LLC	OS	MBRA	NA	NA	NA
7	88FT 8ME LLC	OS	MBRA	NA	NA	NA
8	93LF 8ME LLC	OS	MBRA	NA	NA	NA
9	ADELANTO SOLAR II, LLC	OS	MBRA	NA	NA	NA
10	ADELANTO SOLAR, LLC	OS	MBRA	NA	NA	NA
11	ADERA SOLAR, LLC	OS	MBRA	NA	NA	NA
12	ADOBE SOLAR LLC	OS	MBRA	NA	NA	NA
13	ALGONQUIN SKIC 10 SOLAR, LLC	OS	MBRA	NA	NA	NA
14	ALTA WIND I, LLC	OS	MBRA	NA	NA	NA
	Total					

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1	ALTA WIND II, LLC	OS	MBRA	NA	NA	NA
2	ALTA WIND III, LLC	OS	MBRA	NA	NA	NA
3	ALTA WIND IV, LLC	OS	MBRA	NA	NA	NA
4	ALTA WIND V, LLC	OS	MBRA	NA	NA	NA
5	ALTA WIND V, LLC	AD	MBRA	NA	NA	NA
6	ALTA WIND VIII, LLC	OS	MBRA	NA	NA	NA
7	ALTA WIND X, LLC	OS	MBRA	NA	NA	NA
8	ALTA WIND XI, LLC	OS	MBRA	NA	NA	NA
9	AMERICAN KINGS SOLAR	OS	MBRA	NA	NA	NA
10	AMERICAN SOLAR GREENWORKS, LLC	OS	MBRA	NA	NA	NA
11	ANTELOPE DSR 3 LLC	OS	MBRA	NA	NA	NA
12	AVS PHASE 2, LLC	OS	MBRA	NA	NA	NA
13	BERRY PETROLEUM COMPANY, LLC	OS	MBRA	NA	NA	NA
14	BERRY PETROLEUM COMPANY, LLC	AD	MBRA	NA	NA	NA
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1	BERRY PETROLEUM COMPANY,	OS	MBRA	NA	NA	NA
2	BERRY PETROLEUM COMPANY,	AD	MBRA	NA	NA	NA
3	BISHOP TUNGSTEN DEVELOPMENT LLC	OS	MBRA	NA	NA	NA
4	BLYTHE SOLAR II, LLC	OS	MBRA	NA	NA	NA
5	BLYTHE SOLAR II, LLC	AD	MBRA	NA	NA	NA
6	BLYTHE SOLAR III, LLC	OS	MBRA	NA	NA	NA
7	BROADVIEW ENERGY JN, LLC	OS	MBRA	NA	NA	NA
8	BROADVIEW ENERGY KW, LLC	OS	MBRA	NA	NA	NA
9	CALCITY SOLAR 1, LLC	OS	MBRA	NA	NA	NA
10	CALIFORNIA PV ENERGY LLC	OS	MBRA	NA	NA	NA
11	CALIFORNIA PV ENERGY LLC	AD	MBRA	NA	NA	NA
12	CALIFORNIA WATER SERVICE COMPANY	OS	MBRA	NA	NA	NA
13	CALIFORNIA WATER SERVICE COMPANY	AD	MBRA	NA	NA	NA
14	CALLEGUAS MUNICIPAL WATER	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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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	CALLEGUAS MUNICIPAL WATER	AD	MBRA	NA	NA	NA
2	CALLEGUAS MWD	OS	MBRA	NA	NA	NA
3	CALLEGUAS MWD (SANTA ROSA HYDRO)	OS	MBRA	NA	NA	NA
4	CALLEGUAS MWD (SPRINGVILLE)	OS	MBRA	NA	NA	NA
5	CAMERON RIDGE II	OS	MBRA	NA	NA	NA
6	CATALINA SOLAR 2, LLC	OS	MBRA	NA	NA	NA
7	CE LEATHERS COMPANY	OS	MBRA	NA	NA	NA
8	CED ATWELL ISLAND WEST, LLC	OS	MBRA	NA	NA	NA
9	CED CORCORAN SOLAR 2 LLC	OS	MBRA	NA	NA	NA
10	CED DUCOR 1, LLC	OS	MBRA	NA	NA	NA
11	CED DUCOR 2, LLC	OS	MBRA	NA	NA	NA
12	CED DUCOR 3, LLC	OS	MBRA	NA	NA	NA
13	CED DUCOR 4, LLC	OS	MBRA	NA	NA	NA
14	CEFF II TEHACHAPI PROPERTY, LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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.

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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	CENTRAL ANTELOPE DRY RANCH B, LLC	OS	MBRA	NA	NA	NA
2	CENTRAL ANTELOPE DRY RANCH C, LLC	OS	MBRA	NA	NA	NA
3	CENTRAL HYDROELECTRIC CORP.	OS	MBRA	NA	NA	NA
4	CENTRAL HYDROELECTRIC CORP.	AD	MBRA	NA	NA	NA
5	CES DHS SOLAR, LLC (DHS SOLAR 1)	OS	MBRA	NA	NA	NA
6	CES DHS SOLAR, LLC (DHS SOLAR 2)	OS	MBRA	NA	NA	NA
7	CF SBC MASTER TENANT ONE LLC	OS	MBRA	NA	NA	NA
8	CF SBC MASTER TENANT ONE LLC	OS	MBRA	NA	NA	NA
9	CHEVRON USA	OS	MBRA	NA	NA	NA
10	CHEVRON USA	AD	MBRA	NA	NA	NA
11	CITIZEN SOLAR B, LLC	OS	MBRA	NA	NA	NA
12	CITY OF OXNARD	OS	MBRA	NA	NA	NA
13	CITY OF SANTA ANA	OS	MBRA	NA	NA	NA
14	CITY OF SANTA BARBARA	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CITY OF SANTA BARBARA	AD	MBRA	NA	NA	NA
2	COLMAC ENERGY INCORPORATED	OS	MBRA	NA	NA	NA
3	COPPER MOUNTAIN SOLAR 4, LLC	OS	MBRA	NA	NA	NA
4	CORAM ENERGY LLC	OS	MBRA	NA	NA	NA
5	CORONAL LOST HILLS, LLC	OS	MBRA	NA	NA	NA
6	COSO CLEAN POWER	OS	MBRA	NA	NA	NA
7	DEEP SPRINGS COLLEGE	OS	MBRA	NA	NA	NA
8	DEEP SPRINGS COLLEGE	AD	MBRA	NA	NA	NA
9	DESERT POWER COMPANY	OS	MBRA	NA	NA	NA
10	DESERT STATELINE LLC	OS	MBRA	NA	NA	NA
11	DESERT SUNLIGHT LLC	OS	MBRA	NA	NA	NA
12	DESERT WATER AGENCY	OS	MBRA	NA	NA	NA
13	DESERT WATER AGENCY (SNOW CREEK)	OS	MBRA	NA	NA	NA
14	DESERT WIND III PPC TRUST	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	DESERT WIND II PWR PURCH TRST	OS	MBRA	NA	NA	NA
2	DESERT WINDS II PWR PURCH TRST	AD	MBRA	NA	NA	NA
3	DG SOLAR LESSEE II, LLC-E	OS	MBRA	NA	NA	NA
4	DG SOLAR LESSEE II, LLC-PICO RIVERA	OS	MBRA	NA	NA	NA
5	DG SOLAR LESSEE, LLC HESPERIA	OS	MBRA	NA	NA	NA
6	DG SOLAR LESSEE, LLC (DUNCAN RD	OS	MBRA	NA	NA	NA
7	DG SOLAR LESSEE, LLC (DUNCAN RD	OS	MBRA	NA	NA	NA
8	DG SOLAR LESSEE, LLC (WHITE RD C)	OS	MBRA	NA	NA	NA
9	DG SOLAR LESSEE, LLC (WHITE RD N)	OS	MBRA	NA	NA	NA
10	DG SOLAR LESSEE, LLC (WHITE RD S)	OS	MBRA	NA	NA	NA
11	DIAMOND VALLEY SOLAR LLC	OS	MBRA	NA	NA	NA
12	DILLON WIND LLC	OS	MBRA	NA	NA	NA
13	DIVISION 1	OS	MBRA	NA	NA	NA
14	DIVISION 2	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power 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	DIVISION 3	OS	MBRA	NA	NA	NA
2	DUTCH WIND	OS	MBRA	NA	NA	NA
3	E. F. OXNARD INCORPORATED	OS	MBRA	NA	NA	NA
4	EDOM HILLS PROJECT 1, LLC	OS	MBRA	NA	NA	NA
5	EDOM HILLS PROJECT 1, LLC	AD	MBRA	NA	NA	NA
6	EL CABO WIND LLC	OS	MBRA	NA	NA	NA
7	ELK HILLS POWER, LLC	OS	MBRA	NA	NA	NA
8	ELK HILLS POWER, LLC	AD	MBRA	NA	NA	NA
9	EXPRESSWAY SOLAR C2	OS	MBRA	NA	NA	NA
10	EXXONMOBIL PRODUCTION COMPANY	OS	MBRA	NA	NA	NA
11	EXXONMOBIL PRODUCTION COMPANY	AD	MBRA	NA	NA	NA
12	FREEWAY SPRINGS	OS	MBRA	NA	NA	NA
13	FTS MASTER TENANT 1 LLC(RODEO	OS	MBRA	NA	NA	NA
14	FTS MASTER TENANT 1 LLC(RODEO	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	FTS MASTER TENANT 1 LLC(ESA)	OS	MBRA	NA	NA	NA
2	FTS MASTER TENANT 1 LLC(ESB)	OS	MBRA	NA	NA	NA
3	FTS MASTER TENANT 1 LLC(LDFRB)	OS	MBRA	NA	NA	NA
4	FTS MASTER TENANT 2, LLC (SEPV18)	OS	MBRA	NA	NA	NA
5	GARNET SOLAR POWER GENERATION	OS	MBRA	NA	NA	NA
6	GFP ETHANOL, LLC DBA CALGREN	OS	MBRA	NA	NA	NA
7	GOLDEN SOLAR, LLC	OS	MBRA	NA	NA	NA
8	GOLDEN SPRINGS DEV CO., LLC	OS	MBRA	NA	NA	NA
9	GOLDEN SPRINGS DEVELOP CO.,	OS	MBRA	NA	NA	NA
10	GOLDEN SPRINGS DEVELOP CO.,	OS	MBRA	NA	NA	NA
11	GOLETA WATER DISTRICT	OS	MBRA	NA	NA	NA
12	GOSHEN PHASE II LLC	OS	MBRA	NA	NA	NA
13	GREEN BEANWORKS B LLC	OS	MBRA	NA	NA	NA
14	GREEN BEANWORKS D LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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	HELIOCENTRIC, LLC	OS	MBRA	NA	NA	NA
2	HI HEAD HYDRO INCORPORATED	OS	MBRA	NA	NA	NA
3	HIGHLANDER SOLAR 1	OS	MBRA	NA	NA	NA
4	HIGHLANDER SOLAR 2	OS	MBRA	NA	NA	NA
5	HORSESHOE BEND WIND, LLC	OS	MBRA	NA	NA	NA
6	HORSESHOE BEND WIND, LLC	AD	MBRA	NA	NA	NA
7	HOUWELING NURSERIES OXNARD, INC.	OS	MBRA	NA	NA	NA
8	INDUSTRY METROLINK PV1, LLC	OS	MBRA	NA	NA	NA
9	INDUSTRY SOLAR POWER GENERATION	OS	MBRA	NA	NA	NA
10	ISABELLA FISH FLOW HYDROELECTRIC	OS	MBRA	NA	NA	NA
11	JACUMBA SOLAR, LLC	OS	MBRA	NA	NA	NA
12	KAWEAH RIVER POWER AUTHORITY	OS	MBRA	NA	NA	NA
13	KETTERING 1	OS	MBRA	NA	NA	NA
14	KETTERING 2	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power 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	KONA SOLAR LLC-PARK MERIDIAN 1	OS	MBRA	NA	NA	NA
2	KONA SOLAR LLC-RANCHO CUCAMONGA	OS	MBRA	NA	NA	NA
3	KONA SOLAR LLC-TERRA FRANCESCO 1	OS	MBRA	NA	NA	NA
4	L-8 SOLAR PROJECT, LLC	OS	MBRA	NA	NA	NA
5	LANCASTER LITTLE ROCK C LLC	OS	MBRA	NA	NA	NA
6	LITTLE ROCK-PHAM SOLAR, LLC	OS	MBRA	NA	NA	NA
7	LITTLE ROCK-PHAM SOLAR, LLC	AD	MBRA	NA	NA	NA
8	LOMA LINDA UNIVERSITY	OS	MBRA	NA	NA	NA
9	LOMA LINDA UNIVERSITY	AD	MBRA	NA	NA	NA
10	LONE VALLEY SOLAR PARK I LLC	OS	MBRA	NA	NA	NA
11	LONE VALLEY SOLAR PARK II LLC	OS	MBRA	NA	NA	NA
12	LONGBOAT SOLAR, LLC	OS	MBRA	NA	NA	NA
13	LOWER TULE RIVER IRRIGATION	OS	MBRA	NA	NA	NA
14	LUZ SOLAR PARTNERS LTD. IX	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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	LUZ SOLAR PARTNERS LTD VIII	OS	MBRA	NA	NA	NA
2	MADELYN SOLAR	OS	MBRA	NA	NA	NA
3	MAMMOTH PACIFIC L P II (MP2)	OS	MBRA	NA	NA	NA
4	MARINO VENTURES LLC	OS	MBRA	NA	NA	NA
5	MAVERICK SOLAR, LLC	OS	MBRA	NA	NA	NA
6	MCCOY SOLAR, LLC	OS	MBRA	NA	NA	NA
7	MCCOY SOLAR, LLC	AD	MBRA	NA	NA	NA
8	MESQUITE SOLAR 2, LLC	OS	MBRA	NA	NA	NA
9	MITCHELL SOLAR	OS	MBRA	NA	NA	NA
10	MM TAJIGUAS ENERGY LLC	OS	MBRA	NA	NA	NA
11	MM TULARE ENERGY, LLC	OS	MBRA	NA	NA	NA
12	MOGUL ENERGY PARTNERSHIP I, LLC	OS	MBRA	NA	NA	NA
13	MONTE VISTA WATER DIST	OS	MBRA	NA	NA	NA
14	MORGAN LANCASTER I, LLC	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	MOUNTAINVIEW POWER PARTNERS IV,	OS	MBRA	NA	NA	NA
2	MOUNTAINVIEW POWER PARTNERS, LLC	OS	MBRA	NA	NA	NA
3	MUSTANG HILLS, LLC	OS	MBRA	NA	NA	NA
4	NAVAJO SOLAR POWER GENERATION	OS	MBRA	NA	NA	NA
5	NEWBERRY SOLAR 1 LLC	OS	MBRA	NA	NA	NA
6	NEW-INDY ONTARIO, LLC	OS	MBRA	NA	NA	NA
7	NEW-INDY ONTARIO, LLC	AD	MBRA	NA	NA	NA
8	NEW-INDY OXNARD, LLC	OS	MBRA	NA	NA	NA
9	NICOLIS, LLC	OS	MBRA	NA	NA	NA
10	NORTH HURLBURT WIND, LLC	OS	MBRA	NA	NA	NA
11	NORTH HURLBURT WIND, LLC	AD	MBRA	NA	NA	NA
12	NORTH LANCASTER RANCH, LLC	OS	MBRA	NA	NA	NA
13	NORTH PALM SPRINGS	OS	MBRA	NA	NA	NA
14	NORTH PALM SPRINGS	AD	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power 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)	Average Monthly CP Demand (f)
1	NORTH PALM	OS	MBRA	NA	NA	NA
2	NORTH PALM	AD	MBRA	NA	NA	NA
3	ONE MIRACLE PROPERTY LLC	OS	MBRA	NA	NA	NA
4	ONE TEN PARTNERS, LLC	OS	MBRA	NA	NA	NA
5	ORANGE COUNTY SANITATION DISTRICT	OS	MBRA	NA	NA	NA
6	ORANGE COUNTY SANITATION DISTRICT	AD	MBRA	NA	NA	NA
7	ORION SOLAR SOLAR II	OS	MBRA	NA	NA	NA
8	ORNI 18, LLC	OS	MBRA	NA	NA	NA
9	ORNI 18, LLC	AD	MBRA	NA	NA	NA
10	OTOE SOLAR POWER GENERATION STAT	OS	MBRA	NA	NA	NA
11	PACIFIC ULTRA POWER CHINESE	OS	MBRA	NA	NA	NA
12	PANOCHE VALLEY SOLAR, LLC	OS	MBRA	NA	NA	NA
13	PINYON PINES WIND I, LLC	OS	MBRA	NA	NA	NA
14	PINYON PINES WINDS II, LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	PORTAL RIDGE SOLAR B, LLC	OS	MBRA	NA	NA	NA
2	POWHATAN SOLAR POWER GENERATION	OS	MBRA	NA	NA	NA
3	PROCTER & GAMBLE PAPER PROD	OS	MBRA	NA	NA	NA
4	PROCTER & GAMBLE PAPER PROD	AD	MBRA	NA	NA	NA
5	PROCTER & GAMBLE PAPER PRODUCTS	OS	MBRA	NA	NA	NA
6	PROCTER AND GAMBLE PAPER	OS	MBRA	NA	NA	NA
7	PSOMASFMG LANCASTER SOLAR CREST	OS	MBRA	NA	NA	NA
8	PSOMASFMG LANCASTER SOLAR CREST	OS	MBRA	NA	NA	NA
9	PUMPJACK SOLAR I, LLC	OS	MBRA	NA	NA	NA
10	PVN MILLIKEN, LLC	OS	MBRA	NA	NA	NA
11	RADIANCE SOLAR 4 LLC	OS	MBRA	NA	NA	NA
12	RADIANCE SOLAR 5 LLC	OS	MBRA	NA	NA	NA
13	RE ADAMS EAST	OS	MBRA	NA	NA	NA
14	RE COLUMBIA 3 LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	RE GARLAND A, LLC	OS	MBRA	NA	NA	NA
2	RE GARLAND, LLC	OS	MBRA	NA	NA	NA
3	RE GASKELL WEST 1	OS	MBRA	NA	NA	NA
4	RE ROSAMOND TWO LLC	OS	MBRA	NA	NA	NA
5	RE ROSAMOND TWO LLC	AD	MBRA	NA	NA	NA
6	RE TRANQUILITY 8 AZUL LLC	OS	MBRA	NA	NA	NA
7	RE TRANQUILLITY LLC	OS	MBRA	NA	NA	NA
8	RE VICTOR PHELAN SOLAR ONE LLC	OS	MBRA	NA	NA	NA
9	REC INVENTORY	OS		NA	NA	NA
10	REFRESH WIND 2 LLC	OS	MBRA	NA	NA	NA
11	REFRESH WIND LLC	OS	MBRA	NA	NA	NA
12	REGULUS SOLAR, LLC	OS	MBRA	NA	NA	NA
13	REPUBLIC SERVICES OF SONOMA	OS	MBRA	NA	NA	NA
14	REPUBLIC SERVICES OF SONOMA	AD	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	RIO BRAVO FRESNO	OS	MBRA	NA	NA	NA
2	RIO BRAVO ROCKLIN	OS	MBRA	NA	NA	NA
3	RIO BRAVO SOLAR I	OS	MBRA	NA	NA	NA
4	RIO BRAVO SOLAR II	OS	MBRA	NA	NA	NA
5	RIO GRANDE LLC	OS	MBRA	NA	NA	NA
6	RISING TREE WIND FARM III, LLC	OS	MBRA	NA	NA	NA
7	RISING TREE WIND FARM, LLC	OS	MBRA	NA	NA	NA
8	RUDY SOLAR	OS	MBRA	NA	NA	NA
9	SALTON SEA POWER Generation #2	OS	MBRA	NA	NA	NA
10	SALTON SEA POWER Generation #4	OS	MBRA	NA	NA	NA
11	SAN BERNARDINO MWD	OS	MBRA	NA	NA	NA
12	SAN BERNARDINO MWD	AD	MBRA	NA	NA	NA
13	SAN GORGONIO WESTWINDS II,	OS	MBRA	NA	NA	NA
14	SB COUNTY PUBLIC WORKS DEPT.	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	SECOND IMPERIAL GEOTHERMAL CO.	OS	MBRA	NA	NA	NA
2	SECOND IMPERIAL GEOTHERMAL CO.	AD	MBRA	NA	NA	NA
3	SEPV1	OS	MBRA	NA	NA	NA
4	SEPV II	OS	MBRA	NA	NA	NA
5	SEPV MOJAVE WEST, LLC	OS	MBRA	NA	NA	NA
6	SEPV PALMDALE EAST, LLC	OS	MBRA	NA	NA	NA
7	SEQUOIA PV 1 LLC (FARMERSVILLE 1)	OS	MBRA	NA	NA	NA
8	SEQUOIA PV 1 LLC (FARMERSVILLE 2)	OS	MBRA	NA	NA	NA
9	SEQUOIA PV 1 LLC (FARMERSVILLE 3)	OS	MBRA	NA	NA	NA
10	SEQUOIA PV 1 LLC (TULARE 1)	OS	MBRA	NA	NA	NA
11	SEQUOIA PV 1 LLC (TULARE 2)	OS	MBRA	NA	NA	NA
12	SEQUOIA PV 2 LLC (HANFORD 1)	OS	MBRA	NA	NA	NA
13	SEQUOIA PV 2 LLC (HANFORD 2)	OS	MBRA	NA	NA	NA
14	SEQUOIA PV 3 LLC (PORTERVILLE 6)	OS	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	SEQUOIA PV 3 LLC (PORTERVILLE 7)	OS	MBRA	NA	NA	NA
2	SIERRA SOLAR GREENWORKS, LLC	OS	MBRA	NA	NA	NA
3	SILVER STATE SOLAR POWER SOUTH,	OS	MBRA	NA	NA	NA
4	SKY RIVER PTNRSHP - (WILDERNESS I)	OS	MBRA	NA	NA	NA
5	SKY RIVER PTNRSHP - (WILDERNESS I)	AD	MBRA	NA	NA	NA
6	SKY RIVER PTNRSHP - (WILDERNESS II)	OS	MBRA	NA	NA	NA
7	SKY RIVER PTNRSHP - (WILDERNESS III)	OS	MBRA	NA	NA	NA
8	SOLAR BLYTHE LLC	OS	MBRA	NA	NA	NA
9	SOLAR OASIS LLC	OS	MBRA	NA	NA	NA
10	SOLAR OASIS LLC	AD	MBRA	NA	NA	NA
11	SOLAR PARTNERS I, LLC	OS	MBRA	NA	NA	NA
12	SOLAR STAR CALIFORNIA XIII, LLC	OS	MBRA	NA	NA	NA
13	SOLAR STAR XIX, LLC	OS	MBRA	NA	NA	NA
14	SOLAR STAR XX, LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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.

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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	SOUTH HURLBURT WIND, LLC	OS	MBRA	NA	NA	NA
2	SOUTH HURLBURT WIND, LLC	AD	MBRA	NA	NA	NA
3	SS SAN ANTONIO WEST LLC	OS	MBRA	NA	NA	NA
4	SUMMER SOLAR A2 LLC	OS	MBRA	NA	NA	NA
5	SUMMER SOLAR B2 LLC	OS	MBRA	NA	NA	NA
6	SUMMER SOLAR C2 LLC	OS	MBRA	NA	NA	NA
7	SUMMER SOLAR D2 LLC	OS	MBRA	NA	NA	NA
8	SUN STREAMS	OS	MBRA	NA	NA	NA
9	SUNE SOLAR XVI LESSOR, LLC	OS	MBRA	NA	NA	NA
10	SUNE W12DG-C, LLC	OS	MBRA	NA	NA	NA
11	SUNRAY ENERGY 3, INC.	OS	MBRA	NA	NA	NA
12	SYCAMORE COGENERATION COMPANY(	OS	MBRA	NA	NA	NA
13	SYCAMORE COGENERATION COMPANY(	AD	MBRA	NA	NA	NA
14	SYCAMORE COGENERATION	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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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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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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.

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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	SYCAMORE COGENERATION	AD	MBRA	NA	NA	NA
2	TA-HIGH DESERT, LLC	OS	MBRA	NA	NA	NA
3	TA-HIGH DESERT, LLC	AD	MBRA	NA	NA	NA
4	TECHNI-CAST CORP	OS	MBRA	NA	NA	NA
5	TEMESCAL CANYON (CREST)	OS	MBRA	NA	NA	NA
6	TERRAFORM PHOENIX I CD HOLDINGS,	OS	MBRA	NA	NA	NA
7	TERRA-GEN DIXIE VALLEY, LLC	OS	MBRA	NA	NA	NA
8	TESORO REFINING & MARKETING	OS	MBRA	NA	NA	NA
9	THREE VALLEYS MWD (FULTON)	OS	MBRA	NA	NA	NA
10	THREE VALLEYS MWD (WILLIAMS)	OS	MBRA	NA	NA	NA
11	TKO POWER, LLC (SOUTH BEAR CREEK)	OS	MBRA	NA	NA	NA
12	TROPICO, LLC	OS	MBRA	NA	NA	NA
13	TULARE PV I , LLC (EXETER 1)	OS	MBRA	NA	NA	NA
14	TULARE PV I , LLC (EXETER 2)	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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)	Average Monthly CP Demand (f)
1	TULARE PV I , LLC (EXETER 3)	OS	MBRA	NA	NA	NA
2	TULARE PV I , LLC (IVANHOE 1)	OS	MBRA	NA	NA	NA
3	TULARE PV I , LLC (IVANHOE 2)	OS	MBRA	NA	NA	NA
4	TULARE PV I , LLC (IVANHOE 3)	OS	MBRA	NA	NA	NA
5	TULARE PV I , LLC (LINDSAY 1)	OS	MBRA	NA	NA	NA
6	TULARE PV I , LLC (LINDSAY 3)	OS	MBRA	NA	NA	NA
7	TULARE PV I , LLC (LINDSAY 4)	OS	MBRA	NA	NA	NA
8	TULARE PV I , LLC (POTERVILLE 1)	OS	MBRA	NA	NA	NA
9	TULARE PV I , LLC (POTERVILLE 2)	OS	MBRA	NA	NA	NA
10	TULARE PV I , LLC (POTERVILLE 5)	OS	MBRA	NA	NA	NA
11	TULE WIND LLC	OS	MBRA	NA	NA	NA
12	TULE WIND LLC	AD	MBRA	NA	NA	NA
13	U.S. BORAX INC.	OS	MBRA	NA	NA	NA
14	U.S. BORAX INC.	AD	MBRA	NA	NA	NA
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	UNITED WATER CONSERVATION	OS	MBRA	NA	NA	NA
2	USDA FOREST SERVICE SAN DIMAS	OS	MBRA	NA	NA	NA
3	VALENTINE SOLAR	OS	MBRA	NA	NA	NA
4	VEGA SOLAR, LLC	OS	MBRA	NA	NA	NA
5	VENABLE SOLAR, LLC (NORTH)	OS	MBRA	NA	NA	NA
6	VENABLE SOLAR, LLC (SOUTH)	OS	MBRA	NA	NA	NA
7	VICTOR DRY FARM RANCH A, LLC	OS	MBRA	NA	NA	NA
8	VICTOR DRY FARM RANCH B, LLC	OS	MBRA	NA	NA	NA
9	VICTOR MESA LINDA B2 LLC	OS	MBRA	NA	NA	NA
10	VICTOR MESA LINDA B2 LLC	AD	MBRA	NA	NA	NA
11	VICTOR MESA LINDA C2 LLC	OS	MBRA	NA	NA	NA
12	VICTOR MESA LINDA D2 LLC	OS	MBRA	NA	NA	NA
13	VICTOR MESA LINDA E2 LLC	OS	MBRA	NA	NA	NA
14	VICTORY GARDEN/PHASE IV PARTNER	OS	MBRA	NA	NA	NA
	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.
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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	VICTORY GARDEN/PHASE IV PARTNER	OS	MBRA	NA	NA	NA
2	VICTORY GARDEN/PHASE IV PARTNER	OS	MBRA	NA	NA	NA
3	VOYAGER WIND 1, LLC	OS	MBRA	NA	NA	NA
4	WALNUT VALLEY WATER DISTRICT	OS	MBRA	NA	NA	NA
5	WATSON COGENERATION COMPANY	OS	MBRA	NA	NA	NA
6	WATSON COGENERATION COMPANY	AD	MBRA	NA	NA	NA
7	WHITE MOUNTAIN RANCH LLC	OS	MBRA	NA	NA	NA
8	WILDWOOD SOLAR I	OS	MBRA	NA	NA	NA
9	WILDWOOD SOLAR 1, LLC	OS	MBRA	NA	NA	NA
10	WILDWOOD SOLAR 1, LLC	AD	MBRA	NA	NA	NA
11	WILLOW SPRINGS SOLAR	OS	MBRA	NA	NA	NA
12	WILLOW SPRINGS SOLAR	AD	MBRA	NA	NA	NA
13	WINDHUB SOLAR A	OS	MBRA	NA	NA	NA
14	WINDSTAR ENERGY LLC	OS	MBRA	NA	NA	NA
	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	04/14/2021	End of 2020/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	YAVI ENERGY (EASTWIND)	OS	MBRA	NA	NA	NA
2	GREEN BEANWORKS C LLC	OS	MBRA	NA	NA	NA
3	DEPARTMENT OF ENERGY - HOOVER	LF	333	NA	NA	NA
4	LA DEPT OF WATER & PWR - RET ENGY	OS	MBRA	NA	NA	NA
5	LOWER COLORADO RIVER	OS	MBRA	NA	NA	NA
6	CALIFORNIA ISO - NET	AD	MBRA	NA	NA	NA
7	CALIFORNIA ISO - NET	OS	MBRA	NA	NA	NA
8	DERIVATIVE CONVERSION	OS		NA	NA	NA
9	WECC STATUTORY COSTS	OS		NA	NA	NA
10	HEDGING-CONGESTION REVENUE	OS		NA	NA	NA
11	HEDGING-REALIZED	OS		NA	NA	NA
12	HEDGING-UNREALIZED	OS		NA	NA	NA
13	WECC WREGIS CERTIFICATE	OS		NA	NA	NA
14	ROUNDING ADJUSTMENT					
	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	04/14/2021	End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
					10,800	10,800	2
							3
				2,681,020		2,681,020	4
							5
450				-288,827		-288,827	6
139				29,841		29,841	7
-2,401				-240,106		-240,106	8
91				23,922		23,922	9
							10
					4,237	4,237	11
					5,067	5,067	12
					100	100	13
					23,868	23,868	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/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: 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.
					1,722	1,722	1
					872	872	2
					1,852	1,852	3
					111,312	111,312	4
					4,416,273	4,416,273	5
					1	1	6
					1,320	1,320	7
					237,265	237,265	8
							9
				40,422	1,294,547	1,334,969	10
			3,367,680			3,367,680	11
					20,600,019	20,600,019	12
				168,239		168,239	13
							14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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 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.
			242,034			242,034	1
-55,705				987,734		987,734	2
212,052				11,922,556		11,922,556	3
21,474				630,764		630,764	4
			197,150			197,150	5
							6
161,507				8,199,710		8,199,710	7
4,395				107,363		107,363	8
93,525				5,464,218		5,464,218	9
560				13,204		13,204	10
							11
			51,062,916			51,062,916	12
			9,890,040			9,890,040	13
1,120				26,370		26,370	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
372,848				21,921,241		21,921,241	1
1,191				415,950		415,950	2
159,564				6,186,474		6,186,474	3
29,858				1,635,748		1,635,748	4
			226,200			226,200	5
5,782			10,163,923	308,042		10,471,965	6
			252,480			252,480	7
277,937				11,246,828		11,246,828	8
			59,670			59,670	9
			2,178,440			2,178,440	10
			2,665,000			2,665,000	11
			5,245,000		-12,291,433	-7,046,433	12
			6,672,500			6,672,500	13
			26,254,200			26,254,200	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/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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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)	
207,489			37,412,000	9,795,814		47,207,814	1
							2
			733,860			733,860	3
			54,832			54,832	4
			925,933			925,933	5
					-9,050	-9,050	6
167,858			285,000	8,502,031		8,787,031	7
			47,539,080			47,539,080	8
			1,507,439			1,507,439	9
167,467				10,703,510		10,703,510	10
			2,028,000			2,028,000	11
9,075				1,177,125		1,177,125	12
172,740				7,815,433		7,815,433	13
				3,302		3,302	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
			-6,640			-6,640	1
			545,113			545,113	2
			15,112,500			15,112,500	3
			1,530,160			1,530,160	4
			84,000			84,000	5
			335,760			335,760	6
20,218			11,761,800	939,489		12,701,289	7
10,427				641,556		641,556	8
			127,140			127,140	9
			10,050,840			10,050,840	10
			74,848			74,848	11
120				2,400		2,400	12
			307,217			307,217	13
13,029				881,637		881,637	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
			5,926,729			5,926,729	1
			879,352			879,352	2
							3
			61,106,500			61,106,500	4
			67,599,840			67,599,840	5
1,745,105			52,366,622	52,973,286	174,191	105,514,099	6
594,375			141,420,000	24,077,300	297	165,497,597	7
			766,425	-4,170		762,255	8
			44,620,800			44,620,800	9
393,072			126,645,701	20,316,015	5,661	146,967,377	10
			16,716			16,716	11
			540,000			540,000	12
7,862			4,227,953	517,696	-216	4,745,433	13
396,121			98,213,780	21,980,706	-9,409	120,185,077	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
5,849			8,004,414	435,302	1,001	8,440,717	1
							2
1,245				101,778		101,778	3
							4
7,368				501,563		501,563	5
1,448				138,343		138,343	6
2,164,409				152,912,354		152,912,354	7
6,283				834,745		834,745	8
7,651				693,442		693,442	9
192,546			-138,189	9,977,394	-50,804	9,788,401	10
5,099				438,252		438,252	11
							12
							13
					-32,000	-32,000	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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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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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,547				883,176		883,176	1
17,112				2,168,126		2,168,126	2
61,223			-97,805	4,381,488	-13,911	4,269,772	3
359,187				16,012,923		16,012,923	4
268,470				14,679,493	-2,000	14,677,493	5
34,194			-100,000	2,889,661		2,789,661	6
247,835				17,435,309	-16,064	17,419,245	7
593,689				42,711,021		42,711,021	8
16,401				1,290,354		1,290,354	9
54,460				4,770,912	-137,370	4,633,542	10
37,149				2,839,426		2,839,426	11
45,047				6,562,258		6,562,258	12
18,105				1,618,637		1,618,637	13
375,483				43,158,179		43,158,179	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
322,286				36,980,839		36,980,839	1
331,944				38,041,959		38,041,959	2
164,505				18,938,092		18,938,092	3
256,617				29,675,475		29,675,475	4
-18,552				-26,273		-26,273	5
213,041				25,554,401		25,554,401	6
347,644				37,108,312		37,108,312	7
259,382				28,390,017		28,390,017	8
8,770				266,348		266,348	9
14,542				1,584,726		1,584,726	10
57,122				2,655,198		2,655,198	11
7,108				538,728		538,728	12
288,478			3,085,525	10,142,410	1,512	13,229,447	13
				37,066		37,066	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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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)	
278,217			1,850,502	10,776,671	2,419	12,629,592	1
				28,858		28,858	2
1,282				120,822		120,822	3
272,520				19,192,604		19,192,604	4
				560,265		560,265	5
221,266			-293,352	12,131,483	-14,354	11,823,777	6
699,222				33,957,228		33,957,228	7
549,404				26,684,070		26,684,070	8
8,137				434,522	-200	434,322	9
5,021				837,449		837,449	10
12				36		36	11
1				100		100	12
				-1,537		-1,537	13
5,447				593,421		593,421	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
37				3,979		3,979	1
25				2,321		2,321	2
217				19,634		19,634	3
705				61,465		61,465	4
32,132				1,666,163		1,666,163	5
48,080			-100,000	4,827,121		4,727,121	6
405			3,893	22,061		25,954	7
44,775			-100,000	4,354,933		4,254,933	8
44,851				5,209,435		5,209,435	9
46,755				2,809,391		2,809,391	10
47,154				2,845,449		2,845,449	11
35,321				2,134,051		2,134,051	12
45,681				2,751,290		2,751,290	13
1,858				106,304	-18,000	88,304	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
7,905				615,444		615,444	1
32,948				3,486,347		3,486,347	2
17,746			720,389	469,175		1,189,564	3
				1,565		1,565	4
2,202				273,059		273,059	5
3,522				420,273		420,273	6
2,777				369,242		369,242	7
3,030				391,411		391,411	8
79,640			579,273	2,338,142		2,917,415	9
				7,044		7,044	10
10,504				907,559		907,559	11
							12
52			109	1,352		1,461	13
2,433				262,206		262,206	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/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)	
				-3,445		-3,445	1
					-8,100,000	-8,100,000	2
251,400				17,708,062	-12,404	17,695,658	3
9,678				743,568		743,568	4
46,118				4,268,028		4,268,028	5
					28,812,500	28,812,500	6
92			116	2,269		2,385	7
				-1		-1	8
1,897			17,822	141,144		158,966	9
653,649				106,027,379		106,027,379	10
609,924				94,744,073		94,744,073	11
1,926				170,707		170,707	12
421				37,637		37,637	13
							14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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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)	
21,448			121,715	798,283		919,998	1
-302			-1,900	-10,499		-12,399	2
1,655				232,996		232,996	3
1,633				223,581		223,581	4
2,779				442,172		442,172	5
2,988				379,545		379,545	6
2,361				297,683		297,683	7
3,694				472,293		472,293	8
3,468				432,255		432,255	9
2,969				365,069		365,069	10
2,516				331,612		331,612	11
145,079				10,690,789		10,690,789	12
2,834				363,248		363,248	13
2,021				259,290		259,290	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
1,883				243,315		243,315	1
210			2,224	-915		1,309	2
50,106			760,734	1,941,542		2,702,276	3
29,650			183,467	767,433	-60,000	890,900	4
				42		42	5
1,072,568				53,846,160	-61,113	53,785,047	6
1,143,255			24,546,087	33,299,345		57,845,432	7
			155,167	169,981		325,148	8
3,644				463,289		463,289	9
762			1,236	30,705		31,941	10
				-269		-269	11
3,129				405,329		405,329	12
3,008				360,230		360,230	13
3,795				487,566		487,566	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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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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)	
4,941				418,272		418,272	1
4,271				360,822		360,822	2
12,400				1,206,473		1,206,473	3
5,493				592,237		592,237	4
7,359				801,873		801,873	5
19,499				1,094,663	-18,000	1,076,663	6
3,193				423,260		423,260	7
3,704				908,795		908,795	8
2,702				434,716		434,716	9
2,927				472,545		472,545	10
546				55,336		55,336	11
400,666				43,735,752		43,735,752	12
7,295				393,290		393,290	13
7,577				521,173		521,173	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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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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)	
1,856				266,204		266,204	1
1,330			9,676	79,816		89,492	2
27,397				3,149,439		3,149,439	3
20,799				2,411,955		2,411,955	4
596,178				68,189,371	3,449,688	71,639,059	5
4,642				470,618	-25,150	445,468	6
47,577				2,686,006	-89,777	2,596,229	7
2,501				615,599		615,599	8
4,120				587,185		587,185	9
4,304				425,954		425,954	10
38,673				3,065,042		3,065,042	11
1,373			9,112	58,489		67,601	12
1,828				229,149		229,149	13
2,028				260,000		260,000	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/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)	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.
2,917				403,082		403,082	1
3,066				399,900		399,900	2
2,857				395,027		395,027	3
2,262				321,411		321,411	4
11,752				798,804		798,804	5
8,306				841,398		841,398	6
19				-10,401		-10,401	7
-211			224	-2,787		-2,563	8
36			-260	-5,328		-5,588	9
23,054				1,896,291		1,896,291	10
46,079				3,746,834		3,746,834	11
52,580				3,619,821		3,619,821	12
440				45,938		45,938	13
146,054			16,050,353	5,089,344		21,139,697	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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)	
42,826			693,025	1,282,025		1,975,050	1
2,301				283,197		283,197	2
73,617			1,058,849	2,487,931	-386,320	3,160,460	3
624				77,187		77,187	4
9,040				278,220		278,220	5
567,800				68,592,497	-1,954,558	66,637,939	6
				208,009		208,009	7
263,289				16,722,603		16,722,603	8
4,357				548,556		548,556	9
19,416				1,736,921		1,736,921	10
6,124				511,507		511,507	11
-56			-442	-1,650	82,500	80,408	12
1,549				165,210		165,210	13
3,602				309,962		309,962	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
162,257				19,167,658		19,167,658	1
191,327				18,353,715		18,353,715	2
275,380				32,661,490		32,661,490	3
4,282				604,166		604,166	4
1,837				255,866		255,866	5
48,898			249,120	1,798,668	-52,659	1,995,129	6
				4,061		4,061	7
82,972			520,023	3,043,402	-56,447	3,506,978	8
47,055				3,909,065		3,909,065	9
582,840				66,502,123	3,158,862	69,660,985	10
112				11,185	-43,450	-32,265	11
33,902				3,598,756		3,598,756	12
5,599				910,818		910,818	13
				190		190	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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

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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.
9,639				1,566,837		1,566,837	1
229				26,088		26,088	2
1,302				169,542		169,542	3
5,508				451,968		451,968	4
1,823			6,624	69,589		76,213	5
				3		3	6
16,815				1,430,138	-104,000	1,326,138	7
83,865				6,974,076		6,974,076	8
-5				-379,067		-379,067	9
3,465				497,975		497,975	10
127,047			-36,977	14,647,303	-143,921	14,466,405	11
325,268				24,577,601		24,577,601	12
275,327				34,052,840		34,052,840	13
205,434				25,409,161		25,409,161	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/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)	
48,772				3,549,536		3,549,536	1
4,378				619,007		619,007	2
-1,087			-61,282	-51,727		-113,009	3
				42,195		42,195	4
287,008			2,264,925	11,811,032	-127,559	13,948,398	5
66,447			756,487	2,480,972	-46,029	3,191,430	6
3,223				402,369		402,369	7
3,394				427,880		427,880	8
45,180			-100,000	3,844,088		3,744,088	9
4,767				458,024		458,024	10
3,285				477,002		477,002	11
3,396				492,009		492,009	12
43,468				3,838,335		3,838,335	13
22,984				3,193,774		3,193,774	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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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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.
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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)	
52,824				4,096,175		4,096,175	1
488,050				29,324,125		29,324,125	2
53,235				4,321,024		4,321,024	3
44,057				7,708,855		7,708,855	4
				8,909		8,909	5
45,781				3,645,076		3,645,076	6
427,866				24,888,424	-56,660	24,831,764	7
44,085				7,928,308		7,928,308	8
					688,434	688,434	9
					-15,000	-15,000	10
					-15,000	-15,000	11
142,842				20,327,705	-113,509	20,214,196	12
25,803			-4,922	1,863,820		1,858,898	13
				3		3	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
189,657			-71,745	16,701,901	-186,613	16,443,543	1
179,064			-78,686	21,409,855	-228,258	21,102,911	2
45,835				2,893,174		2,893,174	3
46,213				2,921,160		2,921,160	4
10,428				1,730,631		1,730,631	5
248,527				20,929,682		20,929,682	6
231,150				19,598,726		19,598,726	7
3,738				482,489		482,489	8
25,874			318,115	903,463		1,221,578	9
221,072			5,902,621	7,444,053		13,346,674	10
165			3,194	6,220		9,414	11
				44		44	12
24,907				1,252,964		1,252,964	13
					-45,480	-45,480	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
93,898			2,595,929	2,643,076		5,239,005	1
				9,998		9,998	2
4,657				813,675		813,675	3
3,957				753,621		753,621	4
53,790				3,813,590		3,813,590	5
24,976				1,841,281		1,841,281	6
2,492				328,756		328,756	7
2,629				345,559		345,559	8
2,616				344,790		344,790	9
2,298				268,431		268,431	10
2,371				314,295		314,295	11
2,861				372,161		372,161	12
2,849				371,877		371,877	13
2,564				326,535		326,535	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
2,297				287,272		287,272	1
41,053				3,823,153		3,823,153	2
680,356				95,379,723	-2,920,000	92,459,723	3
-882				-42,115		-42,115	4
			-3,284			-3,284	5
-481			-1,759	-23,170		-24,929	6
-698			-2,231	-33,293		-35,524	7
43,789				5,056,545		5,056,545	8
54,866			-268,064	4,280,665	-325,000	3,687,601	9
			697,363			697,363	10
280,021				48,354,737		48,354,737	11
265,983				34,992,410		34,992,410	12
826,255				101,171,021		101,171,021	13
727,797				89,173,206		89,173,206	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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	04/14/2021	End of 2020/Q4

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

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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.
618,342				71,223,388	3,331,707	74,555,095	1
				-11,915	-12,650	-24,565	2
1,404				358,883		358,883	3
3,766				483,280		483,280	4
3,727				478,283		478,283	5
3,672				467,663		467,663	6
2,267				291,035		291,035	7
395,265				16,878,168	-429,600	16,448,568	8
1,293				173,594		173,594	9
1,615				274,023		274,023	10
34,005				1,744,802		1,744,802	11
664,247			6,864,485	24,515,693	15,968	31,396,146	12
				77,163		77,163	13
50,013			15,308,911	3,898,356	-8,325	19,198,942	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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)	
				495,211	-2	495,209	1
51,319				8,290,724		8,290,724	2
				86,631		86,631	3
599				29,341	-18,000	11,341	4
2,130				294,084		294,084	5
44,173				6,254,972		6,254,972	6
504,250				49,195,006		49,195,006	7
217,337			1,582,850	8,350,103	-92,773	9,840,180	8
795			8,467	25,532	-15,000	18,999	9
882			7,510	30,558	-15,000	23,068	10
-44			-90,233	-2,763		-92,996	11
32,580				2,747,019		2,747,019	12
1,922				248,924		248,924	13
1,916				248,118		248,118	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2021	End of 2020/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)	
2,840				367,852		367,852	1
2,774				358,482		358,482	2
903				117,255		117,255	3
2,774				358,653		358,653	4
2,732				353,757		353,757	5
2,801				363,059		363,059	6
1,854				241,051		241,051	7
1,876				244,593		244,593	8
1,897				247,541		247,541	9
2,814				368,753		368,753	10
342,231			-63,542	20,815,555		20,752,013	11
			72,556			72,556	12
119,683			665,088	4,276,442	-50,859	4,890,671	13
					1	1	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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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)	
1,684			14,775	56,761		71,536	1
28				2,058		2,058	2
253,501				13,050,493	-13,848	13,036,645	3
43,070				3,662,223	-250,000	3,412,223	4
3,386				448,692		448,692	5
3,378				446,885		446,885	6
9,893				999,936		999,936	7
9,837				989,717		989,717	8
3,658				467,604		467,604	9
-4				-453		-453	10
3,657				464,629		464,629	11
3,647				463,464		463,464	12
3,641				463,433		463,433	13
777			2,679	31,785		34,464	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-10			-96	-512		-608	1
930			2,576	37,947		40,523	2
355,305			-49,597	18,065,222	-12,765	18,002,860	3
337				30,395		30,395	4
2,212,306			17,684,100	90,382,224	38,342	108,104,666	5
				244,781		244,781	6
1,113				100,911		100,911	7
37,387				2,374,368		2,374,368	8
44,062			-100,000	3,738,577		3,638,577	9
				2		2	10
253,139				11,362,625	-14,541	11,348,084	11
789				31,689		31,689	12
50,341				2,225,778	-100,283	2,125,495	13
276,939				30,162,215		30,162,215	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,100				584,666		584,666	1
7,837				608,026		608,026	2
167,950			4,452,206	2,206,699	-210,936	6,447,969	3
5,256				154,854		154,854	4
					116,454	116,454	5
					68,310	68,310	6
19,875,161			12,120,890	1,037,942,836	-50,007,419	1,000,056,307	7
					-189,568,556	-189,568,556	8
					3,424,884	3,424,884	9
					-29,271,852	-29,271,852	10
					22,814,135	22,814,135	11
					11,838,503	11,838,503	12
					140,737	140,737	13
-4			-1	-3		-4	14
56,591,078			981,407,572	3,840,898,413	-192,998,766	4,629,307,219	

Schedule Page: 326 Line No.: 1 Column: b

OS 1	"Evergreen" Means Minimum of one year, with automatic annual renewal thereafter. The availability and reliability of energy delivered is on an as-available basis.
OS 2	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.
OS 3	Evergreen Power Purchase 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.
OS 4	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.
OS 7	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.
OS 8	SCE customers on the fringe of SCE's service area.
OS 9	Termination Agreement.
OS 10	Replacement for lost energy due to diversion from Mill Creek.
OS 11	Settlement for generation deviation from transmission service schedule.
OS 12	Quarterly Payments - U.S. Department of Interior, Bureau of Reclamation, Lower Colorado River Multi-Species Conservation Program.
OS 13	Brokers.
OS 14	RA, Energy Storage, Demand Response
OS 15	Low Carbon Fuel Standard (sales) and REC (sales)
OS 16	CALIFORNIA ISO
OS 17	CALIFORNIA AIR RESOURCE BOARD - GHG PHYSICAL EXPENSE
OS 18	CAPITAL LEASE UNDER GAAP
OS 19	UNREALIZED GAIN / LOSS ON FINANCIAL FUTURES OR OPTIONS
OS 20	MISCELLANEOUS OTHER EXPENSE
OS 21	REALIZED GAIN / LOSS ON FINANCIAL FUTURES OR OPTIONS
OS 22	LADWP RETURNED ENERGY
OS 23	RENEWABLE ENERGY CREDITS
LF(5)	TERMINATION DATE: 9/30/2067

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

Facility Charges.

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

OS 17 - Please reference page 326 Line 1 Column (b).

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

Footnote for Col. C:

MBRA - There is no applicable FERC rate Schedule Number or Tariff since SCE understood that these transactions were under the counterparties' Market-Based Ratemaking Authority (MBRA).

Schedule Page: 326 Line No.: 6 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 7 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 8 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 9 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 11 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 11 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326 Line No.: 12 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 12 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326 Line No.: 13 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 13 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326 Line No.: 14 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 1 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 2 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 3 Column: b

OS 13 - 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.: 4 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 5 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 5 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 6 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 6 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 7 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 7 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 8 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.1 Line No.: 8 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.1 Line No.: 10 Column: l

Net Gas Purchases Plus Imbalances.

Schedule Page: 326.1 Line No.: 12 Column: l
Net Gas Purchases Plus Imbalances.
Schedule Page: 326.3 Line No.: 5 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.3 Line No.: 9 Column: b
OS 15 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.3 Line No.: 10 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.3 Line No.: 12 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.3 Line No.: 12 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.3 Line No.: 13 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 3 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 4 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 5 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 6 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 6 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.4 Line No.: 9 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.4 Line No.: 11 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 1 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 2 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 3 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 5 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 6 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 10 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 11 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.5 Line No.: 13 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.6 Line No.: 1 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.6 Line No.: 2 Column: b
OS 14 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.6 Line No.: 6 Column: l
Net Gas Purchases Plus Imbalances.
Schedule Page: 326.6 Line No.: 7 Column: l

California ISO Costs.

Schedule Page: 326.6 Line No.: 10 Column: l

California ISO Costs.

Schedule Page: 326.6 Line No.: 11 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

Schedule Page: 326.6 Line No.: 13 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.6 Line No.: 14 Column: l

California ISO Costs.

Schedule Page: 326.7 Line No.: 1 Column: l

California ISO Costs.

Schedule Page: 326.7 Line No.: 3 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 10 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.7 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.8 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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.: 3 Column: b

OS 4 - 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.: 5 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 7 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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.: 10 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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: 326.9 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
Out of period adjustments due to settlements of billing disputes or updated data.
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 4 - Please reference page 326 Line 1 Column (b).
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.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 13 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.9 Line No.: 14 Column: b
Out of period adjustments due to settlements of billing disputes or updated data.
Schedule Page: 326.10 Line No.: 1 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.10 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.10 Line No.: 2 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

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

Out of period adjustments due to settlements of billing disputes or updated data.

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.: 6 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.10 Line No.: 7 Column: b

OS 4 - 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 4 - 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.

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.: 11 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

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

Out of period adjustments due to settlements of billing disputes or updated data.

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

Out of period adjustments due to settlements of billing disputes or updated data.

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.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 5 Column: b

OS 4 - 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 4 - 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 4 - 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 4 - 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 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.11 Line No.: 14 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 4 Column: b
Out of period adjustments due to settlements of billing disputes or updated data.
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 4 - 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 1 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 10 Column: b
Out of period adjustments due to settlements of billing disputes or updated data.
Schedule Page: 326.12 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 12 Column: b
OS 1 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.12 Line No.: 13 Column: b
OS 3 - 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
Out of period adjustments due to settlements of billing disputes or updated data.
Schedule Page: 326.13 Line No.: 2 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.13 Line No.: 2 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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.: 3 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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.: 6 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.13 Line No.: 7 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 8 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

Schedule Page: 326.13 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

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

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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Schedule Page: 326.16 Line No.: 4 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: 326.16 Line No.: 6 Column: l
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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: 326.18 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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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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Schedule Page: 326.19 Line No.: 11 Column: b
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Schedule Page: 326.19 Line No.: 12 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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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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California ISO Costs.
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Schedule Page: 326.21 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.22 Line No.: 1 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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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: 326.22 Line No.: 10 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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There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.

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Renewable Energy Credits.

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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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California ISO Costs.

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California ISO Costs.

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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.25 Line No.: 7 Column: b

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Schedule Page: 326.25 Line No.: 8 Column: b

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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).
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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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Schedule Page: 326.28 Line No.: 8 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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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).
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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).
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Schedule Page: 326.29 Line No.: 11 Column: b
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.30 Line No.: 1 Column: b
OS 1 - 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.: 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

Out of period adjustments due to settlements of billing disputes or updated data.

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 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 3 Column: b

OS 4 - 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.: 5 Column: b

OS 2 - 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

Out of period adjustments due to settlements of billing disputes or updated data.

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.: 10 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

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.: 11 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.31 Line No.: 12 Column: b

Out of period adjustments due to settlements of billing disputes or updated data.

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.: 13 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.31 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
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.: 3 Column: b
LF(5) - TERMINATION DATE: 9/30/2067
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: b
OS 22 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 5 Column: b
OS 12 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 5 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 6 Column: b
Out of period adjustments due to settlements of billing disputes or updated data.
Schedule Page: 326.32 Line No.: 6 Column: l
California ISO Costs.
Schedule Page: 326.32 Line No.: 7 Column: b
OS 16 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 7 Column: l
California ISO Costs.
Schedule Page: 326.32 Line No.: 8 Column: b
OS 18 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 8 Column: c
There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.
Schedule Page: 326.32 Line No.: 8 Column: l
Capital Lease under GAAP.
Schedule Page: 326.32 Line No.: 9 Column: b
OS 20 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 9 Column: c
There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.
Schedule Page: 326.32 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.32 Line No.: 10 Column: b
OS 19 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 10 Column: c
There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.
Schedule Page: 326.32 Line No.: 10 Column: l
Unrealized Gain / Loss on Financial Futures or Options.
Schedule Page: 326.32 Line No.: 11 Column: b
OS 21 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.32 Line No.: 11 Column: c

There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.

Schedule Page: 326.32 Line No.: 11 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.32 Line No.: 12 Column: b

OS 19 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.32 Line No.: 12 Column: c

There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.

Schedule Page: 326.32 Line No.: 12 Column: l

Unrealized Gain / Loss on Financial Futures or Options.

Schedule Page: 326.32 Line No.: 13 Column: b

OS 20 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.32 Line No.: 13 Column: c

There is no FERC Rate Schedule for this line item as it is not a Company or Public Authority. However, it is an item of Purchase Power Expense.

Schedule Page: 326.32 Line No.: 13 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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			

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	04/14/2021	End of 2020/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	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 Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	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			

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	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	04/14/2021	End of 2020/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	ISO Wheeling	N/A	N/A	AD
6	Mojave Solar LLC	Mojave Solar	ISO	OLF
7	City of Industry	Various	City of Industry	OLF
8	City of Industry	Various	City of Industry	AD
9	Southwest Trans Elec Pwr Coop-AEPCO	Various	SouthwestTransElecPwr Coop-AEPCO	AD
10	City of Riverside	Various	City of Riverside	AD
11	City of Industry	Various	City of Industry	OLF
12	City of Industry	Various	City of Industry	AD
13	Department of Water Resources	Various	Department of Water Resources	OLF
14	Department of Water Resources	Various	Department of Water Resources	AD
15	Pechanga Tribal Utility	Various	Pechanga Tribal Utility	OLF
16	City of Moreno Valley	Various	City of Moreno Valley	OLF
17	City of Vernon	Various	City of Vernon	AD
18	Pechanga Tribal Utility	Various	Pechange Tribal Utility	AD
19	City of Moreno Valley	Various	City of Moreno Valley	AD
20	High Desert Power Trust	Various	High Desert Power Trust	AD
21				
22	Rounding Adjustment			
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
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				8
393.2	San Onofre	Vista				9
207.26	Mead	Laguna Bell	26			10
360.2	Victorville-Lugo	Laguna Bell	11			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				15
372	Mead	Rio Hondo				16
374	Victorville-Lugo	Rio Hondo				17
374	Victorville-Lugo	Rio Hondo				18
375	Mead / Rio Hondo	Mead / Rio Hondo				19
375	Mead / Rio Hondo	Mead / Rio Hondo				20
376	Sylmar	Rio Hondo				21
362	Victorville-Lugo	Vista	3			22
362	Victorville-Lugo	Vista	3			23
361	Mead	Vista				24
361	Mead	Vista				25
363	Victorville-Lugo	Vista				26
363	Victorville-Lugo	Vista				27
365	Devers	Vista				28
365	Devers	Vista				29
364	IPC/Sylmar	Vista				30
379	Victorville-Lugo	Devers	3			31
379	Victorville-Lugo	Devers	3			32
378	Mead	Devers				33
378	Mead	Devers				34
			1,651	**7,140,929**	**7,097,910**	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
381	Devers	Devers				1
381	Devers	Devers				2
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo				3
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo				4
113	El Dorado	Vincent				5
112.3	Devil Canyon	Calectric				6
342	Mohave	Vincent				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				14
Vol. 6, SA #34	Pastoria-Pardee	Various				15
Vol. 6, SA #31	Edmonston-Pastoria	Vincent				16
Vol. 6, SA #32	Vincent	Various				17
Vol. 6, SA #33	Bailey-Sub	Various				18
443	Vincent	Julian Hinds				19
219	Various	Various	368			20
219	Various	Various	368			21
131	Mead	Mountain Center				22
349.8	Various	Various				23
339	Victorville-Lugo	Midway				24
Vol. 5, SA #2	Rio Hondo	Azusa				25
Vol. 5, SA #5	Vista	Riverside City Limit		2,163,008	2,154,140	26
Vol. 5, SA #3	Near Devers	Banning	46	153,230	151,239	27
Vol. 5, SA #3	Near Devers	Banning	46			28
Vol. 5, SA #2	Rio Hondo	Azusa		231,443	227,484	29
Vol. 5, SA #2	Rio Hondo	Azusa				30
Vol. 5, SA #1	Vista	City of Colton		345,846	344,324	31
Vol. 5, SA #1	Vista	City of Colton				32
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39	142,930	138,029	33
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39			34
			1,651	**7,140,929**	**7,097,910**	

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	04/14/2021	End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.				1
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.				2
Vol. 5, SA #77	Mira Loma	Crossings Bus. Ctr.		14,834	14,134	3
Vol. 5, SA #77	Mira Loma	Crossings Bus. Ctr.				4
Vol. 5, SA #56	Vista	Cherry Valley Stn	1	1,512	1,498	5
Vol. 5, SA #56	Vista	Cherry Valley Stn	1			6
Vol. 5, SA #57	Vista	Crafton Hills Stn		16,301	16,042	7
Vol. 5, SA #57	Vista	Crafton Hills Stn				8
Vol. 5, SA #58	San Bernardino	Greenspot Station	4	4,706	4,622	9
Vol. 5, SA #58	San Bernardino	Greenspot Station	4			10
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn		67,996	67,513	11
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn				12
Vol. 5,SA #130	Mira Loma	Cleargen Sub		12,671	12,540	13
Vol. 5,SA #130	Mira Loma	Cleargen Sub				14
Vol. 5,SA #97	Mira Loma	Corona Pointe		19,324	18,754	15
Vol. 5,SA #97	Mira Loma	Corona Pointe				16
Vol. 5,SA #103	Valley Sub	Moreno Valley	3	11,998	11,795	17
Vol. 5,SA #103	Valley Sub	Moreno Valley	3			18
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1	25,405	23,720	19
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1			20
Vol. 5,SA #115	Valley Sub	Moreno Valley		13,327	13,090	21
Vol. 5,SA #115	Valley Sub	Moreno Valley				22
Vol. 5,SA #117	Valley Sub	Moreno Valley	1	2,441	2,406	23
Vol. 5,SA #117	Valley Sub	Moreno Valley	1			24
Vol. 5,SA #143	Valley Sub	Moreno Valley	1	767	748	25
Vol. 5,SA #143	Valley Sub	Moreno Valley	1			26
Vol. 5,SA #128	Valley Sub	Moreno Valley		6,996	6,845	27
Vol. 5,SA #128	Valley Sub	Moreno Valley				28
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Way	2			29
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Wa	2			30
Vol. 5,SA #149	Valley Sub	Moreno Valley	12	76,698	76,368	31
Vol. 5,SA #149	Valley Sub	Moreno Valley	12			32
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2	2,418	2,392	33
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2			34
			1,651	**7,140,929**	**7,097,910**	

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	04/14/2021	End of 2020/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. 5,SA #179	Mountain Center	Anza	14	80,243	73,968	1
Vol. 5,SA #179	Mountain Center	Anza	14			2
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1	14,027	13,674	3
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1			4
Vol. 5,SA #193	Various	Various		29,644	28,215	5
Vol. 5,SA #193	Various	Various				6
Vol. 5,SA #218	Victor Sub	City of Victorville		18,902	18,489	7
Vol. 5,SA #218	Victor Sub	City of Victorville				8
Vol. 5,SA #231	Victor Sub	City of Victorville	12	91,841	86,772	9
Vol. 5,SA #231	Victor Sub	City of Victorville	12			10
Vol. 5,SA #695	Valley Sub	Moreno Valley	1	3,960	3,874	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		1,475,971	1,475,971	14
Vol. 6, SA#33	Bailey-Oso	Edmnstn Pmpng Plant		832,337	832,337	15
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant		190,087	190,087	16
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant		213,184	213,184	17
Vol. 6, SA#31	Vincent	Oso Pumping Plant		96,414	96,414	18
Vol. 6, SA#31	Vincent	Oso Pumping Plant		9,994	9,994	19
131	Mead	Mountain Center				20
131	Mead	Mountain Center				21
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	100,694	100,694	22
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	39,223	39,223	23
Vol. No. 5	Various	Various		29,425	29,425	24
Vol. No. 5	Various	Various		10,263	10,263	25
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		62,731	62,731	26
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		21,545	21,545	27
Vol.	Various	Various		26,044	26,044	28
Vol.	Various	Various		15,410	15,410	29
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		53,855	53,855	30
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		19,181	19,181	31
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	157,730	157,730	32
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	49,385	49,385	33
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct				34
			1,651	**7,140,929**	**7,097,910**	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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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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)	
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct		24,829	24,829	1
Vol. No. 6	Victor Sub	SCE'sCement33kV line	12			2
Vol. No. 6	Victor Sub	SCE'sCement33kV line	12			3
N/A	N/A	N/A				4
N/A	N/A	N/A				5
489.1.0	Sunlot	Kramer				6
Vol.5, SA #737	Walnut Sub	Puente Sub		5,944	5,822	7
Vol.5, SA #737	Walnut Sub	Puente Sub				8
131	Mead	Mountain Center				9
Vol.5, SA #5	Vista	RiversideCityLimits				10
Vol.5, SA #240	Chino Sub	GrandCrossingSub	7	24,224	23,724	11
Vol.5, SA #240	Chino Sub	GrandCrossingSub	7			12
Vol.5, SA #874	El Caso Sub	ClementineMentonePrw	2	12,885	12,668	13
Vol.5, SA #874	El Caso Sub	ClementineMentonePrw	2			14
Vol.5, SA #977	Valley Sub	12Kv@GreatOakPoletop		17,553	16,590	15
Vol.5, SA #972	Valley Sub	Kitching Street	15	99,553	98,129	16
207.26	Mead	Laguna Bell	26			17
Vol.5,SA #977	Valley Sub	Located at Great Oak				18
Vol.5,SA #972	Valley Sub	Kitching Street	15			19
Vol.6,SA #11	Victor Substation	High Desert				20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,651	**7,140,929**	**7,097,910**	

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
1,749,600			1,749,600	2
				3
9,097,920			9,097,920	4
				5
699,840			699,840	6
				7
				8
				9
1,516,320			1,516,320	10
641,520			641,520	11
265,776		30,252	296,028	12
233,280			233,280	13
				14
				15
				16
				17
				18
				19
				20
				21
174,960			174,960	22
				23
				24
				25
				26
				27
				28
				29
				30
174,960			174,960	31
				32
				33
				34
113,574,232	**0**	**4,804,989**	**118,379,221**	

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	04/14/2021	End of 2020/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.
				1
				2
				3
				4
				5
43,200			43,200	6
151,200			151,200	7
				8
				9
		651,331	651,331	10
		402,148	402,148	11
		207,840	207,840	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
21,461,760			21,461,760	20
				21
				22
194,947			194,947	23
				24
		125,331	125,331	25
16,104		1,281,759	1,297,863	26
760,175		993,069	1,753,244	27
63,020		90,279	153,299	28
223,092		46,792	269,884	29
14,123		4,679	18,802	30
218,804		31,815	250,619	31
18,956		2,892	21,848	32
605,000		159	605,159	33
55,000		14	55,014	34
113,574,232	**0**	**4,804,989**	**118,379,221**	

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
91,807		57,858	149,665	3
7,761		5,260	13,021	4
61,710		77	61,787	5
5,610		7	5,617	6
874,038		429	874,467	7
79,458		39	79,497	8
305,800		103	305,903	9
27,800		9	27,809	10
23,540		107	23,647	11
1,378		10	1,388	12
12,925		84	13,009	13
1,175		8	1,183	14
47,749		889	48,638	15
3,706		81	3,787	16
46,101		79	46,180	17
3,393		7	3,400	18
69,543		79	69,622	19
4,708		7	4,715	20
61,980		84	62,064	21
5,516		8	5,524	22
30,690		84	30,774	23
2,790		8	2,798	24
29,040		80	29,120	25
2,640		7	2,647	26
34,257		84	34,341	27
3,009		8	3,017	28
				29
				30
157,352		80	157,432	31
10,440		7	10,447	32
11,220		82	11,302	33
1,020		7	1,027	34
113,574,232	**0**	**4,804,989**	**118,379,221**	

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.
565,591		80	565,671	1
44,660		7	44,667	2
28,867		80	28,947	3
2,589		7	2,596	4
177,799		4,613	182,412	5
16,128		419	16,547	6
62,773		68	62,841	7
5,546		6	5,552	8
164,366		68	164,434	9
13,200		6	13,206	10
21,371		74	21,445	11
1,940		7	1,947	12
				13
				14
		8,323	8,323	15
				16
		2,132	2,132	17
				18
		100	100	19
				20
				21
				22
		784	784	23
				24
		308	308	25
				26
		646	646	27
				28
		154	154	29
				30
		575	575	31
				32
		1,482	1,482	33
				34
113,574,232	**0**	**4,804,989**	**118,379,221**	

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.
		745	745	1
				2
				3
72,962,237			72,962,237	4
-1,957,927			-1,957,927	5
		200,831	200,831	6
20,394		74	20,468	7
1,854		7	1,861	8
				9
				10
90,860		74	90,934	11
8,260		7	8,267	12
261,940		82	262,022	13
10,000		7	10,007	14
434,313		88,911	523,224	15
186,775		77	186,852	16
				17
39,483		8,083	47,566	18
13,500		7	13,507	19
				20
				21
		5	5	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
113,574,232	**0**	**4,804,989**	**118,379,221**	

Name of Respondent Southern California Edison Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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: h
Billing Demand N/A
Schedule Page: 328 Line No.: 8 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 9 Column: h
Billing Demand N/A
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: h
Billing Demand N/A

Schedule Page: 328 Line No.: 15 Column: m
Customer charge per agreement.

Schedule Page: 328 Line No.: 16 Column: h
Billing Demand N/A

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: h
Billing Demand N/A

Schedule Page: 328 Line No.: 17 Column: m
Customer charge per agreement.

Schedule Page: 328 Line No.: 18 Column: h
Billing Demand N/A

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: h
Billing Demand N/A

Schedule Page: 328 Line No.: 19 Column: m
Customer charge per agreement.

Schedule Page: 328 Line No.: 20 Column: h
Billing Demand N/A

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: h
Billing Demand N/A

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: h
Billing Demand N/A

Schedule Page: 328 Line No.: 24 Column: m
Customer charge per agreement.

Schedule Page: 328 Line No.: 25 Column: h
Billing Demand N/A

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: h
Billing Demand N/A
Schedule Page: 328 Line No.: 26 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 27 Column: h
Billing Demand N/A
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 N/A
Schedule Page: 328 Line No.: 28 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 29 Column: h
Billing Demand N/A
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: h
Billing Demand N/A
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: h
Billing Demand N/A
Schedule Page: 328 Line No.: 33 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 34 Column: h
Billing Demand N/A
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: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 1 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 2 Column: h
Billing Demand N/A
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: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 3 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 4 Column: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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/Take serv

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: h

Billing Demand N/A

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: m

Customer charge plus facility charge per agreement.

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: m

Customer charge plus facility charge per agreement.

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 10.2

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 10.2

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 - 7/21/53

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 - 4/11/2034

Schedule Page: 328.2 Line No.: 17 Column: m

Customer charge plus facility charge per agreement.

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 - 6/1/38

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 0.2

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 0.2

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: m

Customer charge plus facility charge per agreement.

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: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 14 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 15 Column: h

Billing Demand N/A

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: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 16 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 17 Column: h

Billing Demand N/A

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: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 18 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 19 Column: h

Billing Demand N/A

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: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 20 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 21 Column: h

Billing Demand N/A

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 0.2
Schedule Page: 328.3 Line No.: 34 Column: m
Reliability Services Charge.
Schedule Page: 328.4 Line No.: 1 Column: h
Billing Demand 0.2
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: m
Reliability Services Charge.
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: h
Billing Demand N/A
Schedule Page: 328.4   Line No.: 6   Column: d
OLF - 02/08/2012/Cust.Termin.
Schedule Page: 328.4   Line No.: 6   Column: h
Billing Demand N/A
Schedule Page: 328.4   Line No.: 6   Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.
Schedule Page: 328.4   Line No.: 7   Column: d
OLF - 12/17/34
Schedule Page: 328.4   Line No.: 7   Column: h
Billing Demand 1.8
Schedule Page: 328.4   Line No.: 7   Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.4   Line No.: 8   Column: h
Billing Demand 1.8
Schedule Page: 328.4   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: 328.4   Line No.: 9   Column: h
Billing Demand N/A
Schedule Page: 328.4   Line No.: 9   Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328.4   Line No.: 10   Column: h
Billing Demand N/A
Schedule Page: 328.4   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: 328.4   Line No.: 11   Column: d
OLF - 9/10/45
Schedule Page: 328.4   Line No.: 11   Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.4   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: 328.4   Line No.: 13   Column: d
OLF - Plant Life
Schedule Page: 328.4   Line No.: 13   Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.4   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: 328.4   Line No.: 15   Column: d
OLF - 10/01/2047
Schedule Page: 328.4   Line No.: 15   Column: h
Billing Demand 16.05
Schedule Page: 328.4   Line No.: 15   Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.4   Line No.: 16   Column: d
OLF - 11/17/2047
Schedule Page: 328.4   Line No.: 16   Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.4   Line No.: 17   Column: m
Customer charge per agreement. Revenue received in current year for prior year's service period.
Schedule Page: 328.4   Line No.: 18   Column: h
Billing Demand 16.05

Schedule Page: 328.4 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: 328.4 Line No.: 19 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 20 Column: h

Billing Demand N/A

Schedule Page: 328.4 Line No.: 20 Column: m

Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

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	04/14/2021	End of 2020/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					
6					
7					
8					
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11					
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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) 04/14/2021	Year/Period of Report End of 2020/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	WAPA Blythe	OLF					140,020	140,020
2	WAPA Mead/Parker	OLF					231,062	231,062
3	Bonneville Power Admin	FNS	6,369,752	6,369,752		16,072,981		16,072,981
4	Nevada Power Company	FNS	12,855	12,855		69,499		69,499
5	PacifiCorp	FNS	552,868	552,868		4,131,641		4,131,641
6	WAPA - Desert SW Region	FNS	97,196	97,196		343,444		343,444
7								
8								
9	Rounding							
10								
11								
12								
13								
14								
15								
16								
	TOTAL		7,032,671	7,032,671		20,617,565	371,082	20,988,647

Name of Respondent Southern California Edison Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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

Western Area Power Administration (Western) -Blythe

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

OLF - 1 Year Notice

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

(1) Blythe O&M and Common Use fee charge to SCE.

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

Western Area Power Administration (Western) -Mead/Parker

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

OLF - 1 Year Notice

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

(2) Transmission Service Charge to SCE.

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

Bonneville Power Administration

Schedule Page: 332 Line No.: 6 Column: a

Western Area Power Administration-Desert SW Region

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	04/14/2021	End of 2020/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,621,238
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	13,622,021
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	722,900
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Credit Line/Bank Charges	8,163,373
7	Director Fees	3,146,544
8	SEC Reports	621,300
9	Plan & Dev of Com Sys	3,710,070
10	Provision for Doubtful Accounts-Non-Energy Billings	7,099,196
11	Vendor Discounts	-13,995,173
12	Accounting Suspense	-10,682
13	Miscellaneous	753,757
14		
15		
16	Admin and Gen by Other	12,450,390
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
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45		
46	TOTAL	38,904,934

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	04/14/2021	End of 2020/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			223,300,352		223,300,352
2	Steam Production Plant					
3	Nuclear Production Plant	18,377,160			4,325,850	22,703,010
4	Hydraulic Production Plant-Conventional	28,032,778				28,032,778
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	71,150,000				71,150,000
7	Transmission Plant	380,181,666			78,272	380,259,938
8	Distribution Plant	1,027,519,644			7,696,890	1,035,216,534
9	Regional Transmission and Market Operation					
10	General Plant	260,971,645				260,971,645
11	Common Plant-Electric	10,445				10,445
12	TOTAL	1,786,243,338		223,300,352	12,101,012	2,021,644,702

B. Basis for Amortization Charges

The basis used to compute the charges is the ending plant balance. The basis is different from the preceding year due to net plant additions throughout the year.

Account 404
The amortization of Intangible Plant is based on the following:

Capsoft and other misc.: Based on the anticipated useful life
Hydro Relicensing: 1.85%
Radio Frequency: 2.50%
Other Intangibles: 5.00%

Account 405
The amortization of the SUNK costs for Palo Verde Plant based on the end of life as authorized by Utility Retained Generation Decision 04-04-016.
The amortization of the Beyond the Meter Costs for Distribution based on a 10 year life as authorized by Decision 14-03-021.

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					Life Span	
15	312					Life Span	
16	314					Life Span	
17	315					Life Span	
18	316					Life Span	
19							
20							
21	NUCLEAR PRODUCTION						
22	PVNGS 1,2 & 3						
23	320.2		31.00			License	25.54
24	321	237,415	29.00			License	24.14
25	322	155,721	28.00	-3.70		License	22.75
26	323	94,333	25.00	-5.90		License	19.95
27	324	23,050	30.00	-0.60		License	24.84
28	325	71,016	29.00	-2.00		License	23.68
29							
30							
31	HYDRAULIC						
32	330.2	3,216	60.00		1.95	License	31.33
33	331	238,281	54.00	-12.40	2.19	License	33.29
34	332	621,894	61.00	-6.90	1.99	License	26.17
35	333	199,147	53.00	-11.30	2.11	License	30.93
36	334	229,384	46.00	-15.10	2.48	License	31.36
37	335	13,738	52.00	-2.20	1.58	License	25.86
38	336	25,714	45.00	-16.10	2.56	License	29.78
39							
40							
41	OTHER PRODUCTION						
42	340.2	527	30.00			Life Span	16.57
43	341	102,443	29.00			Life Span	15.96
44	342	16,537	32.00			Life Span	17.71
45	343	1,172,384	25.00		2.00	Life Span	13.25
46	344	119,850	32.00			Life Span	17.71
47	345	207,124	29.00			Life Span	15.96
48	346	116,477	32.00			Life Span	17.71
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	TRANSMISSION PLANT						
13	350.2	213,722	60.00		1.67	Judgement*	55.00
14	352	1,253,035	55.00	-35.00	2.41	L 1.0	43.51
15	353	6,960,254	45.00	-15.00	2.58	R 0.5	33.88
16	354	2,395,871	65.00	-60.00	2.46	R 5.0	50.88
17	355	1,828,031	65.00	-72.00	2.54	SC	54.96
18	356	1,891,226	61.00	-80.00	2.83	R 3.0	43.90
19	357	325,221	55.00		1.73	R 3.0	35.60
20	358	406,148	45.00	-15.00	2.30	S 1.0	29.96
21	359	215,838	60.00		1.65	R 5.0	50.00
22							
23	DISTRIBUTION PLANT						
24	360.2	61,494	60.00		1.67	Judgement*	55.00
25	361	844,614	50.00	-25.00	2.27	L 0.5	36.45
26	362	3,106,964	65.00	-25.00	1.90	L 0.5	51.24
27	363	14,174	10.00		10.00	Judgement*	9.00
28	364	3,866,742	55.00	-210.00	5.96	R 1.0	42.17
29	365	2,407,047	55.00	-115.00	3.85	R 0.5	40.07
30	366	2,841,543	59.00	-30.00	2.27	R 3.0	40.80
31	367	6,927,675	43.00	-60.00	3.51	R 1.5	29.56
32	368	4,893,772	33.00	-20.00	4.35	R 1.5	17.50
33	369	1,687,641	55.00	-100.00	3.27	S 1.5	36.79
34	370	1,066,410	20.00	-5.00	5.99	R 3.0	8.15
35	371	12,742	45.00	15.00	4.34	R 1.5	40.00
36	373	855,518	48.00	-30.00	2.79	L 1.0	32.07
37							
38	GENERAL						
39	389.2	3,282	60.00		1.67	Judgement*	55.00
40	390	1,127,687	45.00	-10.00	2.08	R 0.5	32.39
41	391.XXX	932,388	9.00		15.62	Judgement*	4.61
42	392.4		7.00		14.29	Judgement*	2.00
43	393	10,651	20.00		5.00	Judgement*	7.06
44	394.6		10.00		10.00	Judgement*	5.00
45	395	131,694	15.00		6.67	Judgement*	4.81
46	396	789	15.00		6.67	Judgement*	4.68
47	397	1,060,060	6.00		11.50	Judgement*	0.91
48	398	40,637	20.00		5.00	Judgement*	9.93
49							
50	TOTAL	51,031,311					

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	ER19-1553		15,767	15,767	
8	Formula Rate 2019				
9	LA2019000105				
10					
11	A.06-08-011, D.07-03-013,		5,376	5,376	
12	EL11-8, EL11-11, AD16-20, RM16-23				
13	ISO/TO/RTO/VARIOUS TRANS & MKT ISSUES				
14	LA2006000712				
15					
16	A.08-07-021, D.09-09-047		19,020	19,020	
17	CEES - CUSTOMER ENERGY EFF & SOLAR GRP				
18	LA2010000646				
19					
20	A.15-01-014, A15-02-006		5,283	5,283	
21	NUCLEAR FUEL TRADING AGREEMENTS				
22	LA2014000271				
23					
24	A.16-09-001		296,167	296,167	
25	GENERAL RATE CASE				
26	LA2012000405				
27					
28	A.18-11-009		43,328	43,328	
29	ERRA OSC LA2019000115				
30					
31					
32	A.19-04-014 et al (A.19-04-015, A.19-04-017,		6,420	6,420	
33	A.19-04-018)				
34	2020 COST OF CAPITAL ASSISTANCE				
35	LA2019000251				
36					
37	A.19-07-020		47,115	47,115	
38	WEMA INSURANCE RECOVERY				
39	LA2019000213				
40					
41	A.19-10-001		77,538	77,538	
42	BPA EE APPLICATION				
43	LA2019000109				
44					
45	C.17-10-013		10,299	10,299	
46	TOTAL	9,641,158	2,201,571	11,842,729	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	ANSWER TO WRIT PETITION				
2	LA2020000089				
3					
4	EL 19-82-000		5,511	5,511	
5	HARBOR COGEN COMPLAINT CASE				
6	LA2019000239				
7					
8	EL00-95-000, EL00-98-000		836,727	836,727	
9	FERC INVESTIGATION				
10	LA2000000853				
11					
12	EL13-71, EL15-52, QF13-403		1,480	1,480	
13	WINDING CREEK SOLAR ENFORCEMENT ACTION				
14	LA2013000342				
15					
16	I.12-10-013 et al., R.15-02-020, R.18-07-003		1,187	1,187	
17	SONGS OII				
18	LA2012002218				
19					
20	A.20-10-018		14,378	14,378	
21	CATALINA WATER GRC				
22	LA2020000183				
23					
24	No Docket		21,352	21,352	
25	ANTITRUST ADVICE				
26	LA2015000253				
27					
28	No Docket		14,940	14,940	
29	FERC DATA PRESERVATION REQ (E-DISCOVERY)				
30	LA2018000729				
31					
32	No Docket		876	876	
33	FERC DATA PRESERVATION REQUEST RE OUTAGE				
34	LA2018000609				
35					
36	No Docket		144,792	144,792	
37	FIXED FEE AGMT-JENNIFER KEY (2018)				
38	LA2018000033				
39					
40	No Docket		1,914	1,914	
41	SAN FRANCISCO OFFICE				
42	LA2004001099				
43					
44	No Docket		12,195	12,195	
45	TRANSCRIPTS-CPUC (ONLY)				
46	TOTAL	9,641,158	2,201,571	11,842,729	

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	04/14/2021	End of 2020/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	LA1990000067				
2					
3	QM09-XX		45,385	45,385	
4	APPLICATION FOR RELIEF FROM PURPA PURCH				
5	LA2009000724				
6					
7	R.11-09-011		49,780	49,780	
8	INTERCONNECTION ISSUES				
9	LA2008000697				
10					
11	R.14-07-002		133,498	133,498	
12	NEM ANTITRUST				
13	LA2014000357				
14					
15	R.17-06-026		489	489	
16	PCIA OIR (E-DISCOVERY)				
17	LA2017000734				
18					
19	RM07-1		25,882	25,882	
20	SOC AND OTHER FERC COMPLIANCE MATTERS				
21	LA2004000567				
22					
23	R.19-07-017		2,450	2,450	
24	AB 1054 (E-DISCOVERY)				
25	LA2019000422				
26					
27	A.19-10-001		14,712	14,712	
28	BPA EE APPLICATION (E-DISCOVERY)				
29	LA2020000027				
30					
31	R.19-07-017		14,430	14,430	
32	DWR SERVICING AGREEMENT				
33	LA2020000115				
34					
35	R.20-08-022		4,453	4,453	
36	FINANCING OIR				
37	LA2020000388				
38					
39	EL14-40-000, EC13-114, A.13-10-020		4,399	4,399	
40	MORONGO TRANSACTION FOR WEST OF DEVERS				
41	LA2020000341				
42					
43	R.17-06-026		234,685	234,685	
44	PCIA Writ				
45	LA2020000073				
46	TOTAL	9,641,158	2,201,571	11,842,729	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1					
2	I.12-10-013, A.18-03-009		384,206	384,206	
3	SONGS CANISTER REVIEW				
4	LA2020000078				
5					
6	I.12-10-013, A.18-03-009		18,936	18,936	
7	SONGS CANISTER REVIEW (E-DISCOVERY)				
8	LA2020000140				
9					
10	I.00-11-001		51,469	51,469	
11	TARIFFS & RULES LA2018000398				
12					
13	A.18-04-001		49,902	49,902	
14	WEMA CLAIMS RECOVERY				
15	LA2020000405				
16					
17	R.18-10-007		4,970	4,970	
18	WILDFIRE MITIGATION PLAN DEFICIENCIES				
19	LA2020000308				
20					
21	R.11-03-012, R.14-08-013		-419,737	-419,737	
22	LOW CARBON FUEL STANDARDS LCFS - CFRP				
23	LA2019000024				
24					
25					
26					
27	YEAR END ACCRUALS				
28	PROCUREMENT/EQUIPMENT SERVICES				
29	REGULATORY COMMISSION EXPENSES:				
30	ISO FERC FEES	5,148,642		5,148,642	
31	INTERVENOR COMPENSATION	4,492,516		4,492,516	
32					
33	EMPLOYEES SALARIES AND EXPENSES RELATED				
34	TO FORMAL CASES:				
35	FERC Applications				
36	Minor Items (Less than $25,000)				
37					
38	ROUNDING ADJUSTMENT		-3	-3	
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	9,641,158	2,201,571	11,842,729	

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	04/14/2021	End of 2020/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
ELECTRIC	928	15,767					7
							8
							9
							10
ELECTRIC		5,376					11
							12
							13
							14
							15
ELECTRIC		19,020					16
							17
							18
							19
ELECTRIC		5,283					20
							21
							22
							23
ELECTRIC		296,167					24
							25
							26
							27
ELECTRIC	928	43,328					28
							29
							30
							31
ELECTRIC	928	6,420					32
							33
							34
							35
							36
ELECTRIC	928	47,115					37
							38
							39
							40
ELECTRIC	928	77,538					41
							42
							43
							44
ELECTRIC	928	10,299					45
		11,842,729					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	04/14/2021	End of 2020/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
ELECTRIC	928	5,511					4
							5
							6
							7
ELECTRIC	928	836,727					8
							9
							10
							11
ELECTRIC	928	1,480					12
							13
							14
							15
ELECTRIC	928	1,187					16
							17
							18
							19
ELECTRIC	928	14,378					20
							21
							22
							23
ELECTRIC	928	21,352					24
							25
							26
							27
ELECTRIC	928	14,940					28
							29
							30
							31
ELECTRIC	928	876					32
							33
							34
							35
ELECTRIC	928	144,792					36
							37
							38
							39
ELECTRIC	928	1,914					40
							41
							42
							43
ELECTRIC	928	12,195					44
							45
		11,842,729					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	04/14/2021	End of 2020/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
ELECTRIC	928	45,385					3
							4
							5
							6
ELECTRIC	928	49,780					7
							8
							9
							10
ELECTRIC	928	133,498					11
							12
							13
							14
ELECTRIC	928	489					15
							16
							17
							18
ELECTRIC	928	25,882					19
							20
							21
							22
ELECTRIC	928	2,450					23
							24
							25
							26
ELECTRIC	928	14,712					27
							28
							29
							30
ELECTRIC	928	14,430					31
							32
							33
							34
ELECTRIC	928	4,453					35
							36
							37
							38
ELECTRIC	928	4,399					39
							40
							41
							42
ELECTRIC	928	234,685					43
							44
							45
		11,842,729					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	04/14/2021	End of 2020/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	384,206					2
							3
							4
							5
ELECTRIC	928	18,936					6
							7
							8
							9
ELECTRIC	928	51,469					10
							11
							12
ELECTRIC	928	49,902					13
							14
							15
							16
ELECTRIC	928	4,970					17
							18
							19
							20
ELECTRIC	928	-419,737					21
							22
							23
							24
							25
							26
ELECTRIC	928						27
ELECTRIC	928						28
							29
ELECTRIC	928	5,148,642					30
ELECTRIC	928	4,492,516					31
							32
							33
							34
							35
							36
							37
		-3					38
							39
							40
							41
							42
							43
							44
							45
		11,842,729					46

Schedule Page: 350.3   Line No.: 21   Column: a

Note: Transfer EB Energy Law Costs from 401354 to 34518. JE# 1001875429

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	04/14/2021	End of 2020/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	Electric RD&D Performed Internally:	
2	(1) Generation:	
3		
4	(2) Transmission:	
5		
6	A(3) - Distribution	Technology Demonstration for the Distribution Grid
7		
8	A(5) - Environmental	EPRI
9		
10		
11		
12		
13	A(6) - Other	Energy Efficiency
14		Demand Response
15		
16	A(6) - Other	
17		
18		
19		
20		
21		
22		
23		
24		
25	Total Research and Development	
26		
27		
28		
29		
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
					2
					3
					4
					5
3,579,736	11,564,499	930/584	15,144,235		6
					7
	376,313	920	376,313		8
					9
					10
					11
					12
2,483,205	5,792,651	907/908	8,275,856		13
658,947	2,498,016	907/908	3,156,964		14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
6,721,888	20,231,479		26,953,368		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	62,633,241		
4	Transmission	92,962,362		
5	Regional Market			
6	Distribution	180,830,596		
7	Customer Accounts	81,623,135		
8	Customer Service and Informational	75,364,151		
9	Sales	2,875,130		
10	Administrative and General	241,620,815		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	737,909,430		
12	Maintenance			
13	Production	17,293,558		
14	Transmission	20,320,443		
15	Regional Market			
16	Distribution	133,189,047		
17	Administrative and General	2,994,714		
18	TOTAL Maintenance (Total of lines 13 thru 17)	173,797,762		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	79,926,799		
21	Transmission (Enter Total of lines 4 and 14)	113,282,805		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	314,019,643		
24	Customer Accounts (Transcribe from line 7)	81,623,135		
25	Customer Service and Informational (Transcribe from line 8)	75,364,151		
26	Sales (Transcribe from line 9)	2,875,130		
27	Administrative and General (Enter Total of lines 10 and 17)	244,615,529		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	911,707,192		911,707,192
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	37,575		
37	Customer Accounts	62,654		
38	Customer Service and Informational			
39	Sales			
40	Administrative and General	648,029		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	748,258		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply	155,213		
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	320,760		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	475,973		
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)	155,213		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	358,335		
58	Customer Accounts (Line 37)	62,654		
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	648,029		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	1,224,231		1,224,231
63	Other Utility Departments			
64	Operation and Maintenance	4,605,498		4,605,498
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	917,536,921		917,536,921
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	970,181,268		970,181,268
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	970,181,268		970,181,268
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	5,905,269		5,905,269
79	Nonutility Operations	8,604,913		8,604,913
80	Miscellaneous Other Accounts	30,229,426		30,229,426
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	44,739,608		44,739,608
96	TOTAL SALARIES AND WAGES	1,932,457,797		1,932,457,797

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	04/14/2021	End of 2020/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT IN SERVICE

ACCOUNT	BALANCE BEGINNING OF YEAR	ADDITIONS	RETIREMENTS	BALANCE END OF YEAR
Structures and Improvements	$ 1,000,501	$ -	$ -	$ 1,000,501
Office Furniture and Equipment	-	-	-	-
Transportation Equipment	-	-	-	-
Stores Equipment	-	-	-	-
Tools, Shop and Garage Equipment	-	-	-	-
Communication Equipment	-	-	-	-
Miscellaneous Equipment	-	-	-	-
Total Common Utility Plant in Service	1,000,501	-	-	1,000,501
Construction Work in Progress	-	-	-	-
Total Common Utility Plant	$ 1,000,501	$ -	$ -	$ 1,000,501

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	04/14/2021	End of 2020/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	$ -
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	$ -

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

Total Common Utility Plant,Page 201,line 8		$ 1,000,501
Electric Department	60%	600,301
Gas Department	15%	150,075
Water Department	25%	250,125
		$ 1,000,501

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	04/14/2021	End of 2020/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.

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

Total Common CWIP,Page 201,line 11		$ -
Electric Department	60%	-
Gas Department	15%	-
Water Department	25%	-
		$ -

Note: CPUC Standard Practice U-6-W allows for the allocation of common utility plant and provides guidance for utilities in establishing respective allocation methods. Most recently SCE’s allocation of common utility plant and accumulated depreciation for its Catalina was authorized in CPUC Decision (D.)14-10-048 on 10/16/14 adopting an all-party settlement in SCE’s 2011 Water General Rate Case.

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	04/14/2021	End of 2020/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.
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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 COMMON UTILITY PLANT MADE ON REVENUE BASIS

Accumulated Provision for Depreciation of Common Utility Plant

	General Plant Account 119.300	General Other Account 119.400	Total
Balance Beginning of the Year	$ 583,623	$ -	$ 583,623
Depreciation Provision for Year Charged to:			
Depreciation Expense	17,409	-	17,409
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	17,409	-	17,409
Balance End of the Year	$ 601,032	$ -	$ 601,032

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	04/14/2021	End of 2020/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.

Departmental Allocation of Accumulated Provision
For Depreciation, Common Utility Plant Made on
a Revenue Basis

Accumulated Provision for Depreciation, Page 201, line 14		$ 601,032
		============
Electric Department	60%	360,619
Gas Department	15%	90,155
Water Department	25%	150,258

		$ 601,032
		============

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	186,732,002	96,053,318	459,638,612	259,364,647
8	Net Sales-Day Ahead Market (Account 447)	2,620,269	1,412,086	(3,550,756)	4,557,690
9	Net Purchases-Real Time Market (Acct 555	14,018,963	17,964,058	42,379,546	41,229,109
10	Net Sales-Real Time Market (Account 447)	(10,291,040)	(9,329,481)	(28,661,779)	(3,913,712)
11	Access Charge (Account 555)	308,372	121,671	398,483	256,750
12	Ancillary Services (Account 555)	2,023,930	217,205	2,386,409	7,202,338
13	Cost Recovery (Account 555)	1,259,589	1,312,420	(1,064,238)	4,040,609
14	Day Ahead EnergyCongestion(Gains)/Losses	(22,160,445)	(16,203,843)	(97,554,235)	(42,790,862)
15	HourAheadScheduling Process-RTSettlement	5,243,561	5,149,997	17,409,605	30,918,044
16	GMC (Account 561.4 & 575.7)	8,871,600	10,449,544	13,983,696	9,333,060
17	Ferc Fees (Account 928)	1,020,314	1,044,577	2,041,669	1,049,421
18	Other (Account 555)	2,945,374	30,649	(1,466,846)	1,233,169
19					
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43					
44					
45					
46	TOTAL	192,592,489	108,222,201	405,940,166	312,480,263

Schedule Page: 397 Line No.: 7 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.

Schedule Page: 397 Line No.: 7 Column: c

(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.

Schedule Page: 397 Line No.: 7 Column: d

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Schedule Page: 397 Line No.: 7 Column: e

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Schedule Page: 397 Line No.: 8 Column: b

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(2) These charges are not recorded to A/C 555.

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.: 11 Column: b

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Schedule Page: 397 Line No.: 13 Column: c

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Schedule Page: 397 Line No.: 14 Column: b

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Schedule Page: 397 Line No.: 14 Column: c

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Schedule Page: 397 Line No.: 15 Column: b

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Schedule Page: 397 Line No.: 15 Column: c

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Schedule Page: 397 Line No.: 15 Column: d

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Schedule Page: 397 Line No.: 16 Column: b

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(2) These charges are not recorded to A/C 555.

Schedule Page: 397 Line No.: 16 Column: c

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Schedule Page: 397 Line No.: 17 Column: b

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Schedule Page: 397 Line No.: 18 Column: b

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Schedule Page: 397 Line No.: 18 Column: c

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Schedule Page: 397 Line No.: 18 Column: e

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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	04/14/2021	End of 2020/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		MWh			MWh	
2	Reactive Supply and Voltage		MW			MW	
3	Regulation and Frequency Response	2,238,361	MW	25,129,756	1,961,403	MW	-16,435,768
4	Energy Imbalance		MWh			MWh	
5	Operating Reserve - Spinning	1,797,771	MW	22,516,066	2,639,592	MW	-19,560,976
6	Operating Reserve - Supplement	1,577,511	MW	13,733,654	3,996,963	MW	-12,888,796
7	Other		MW			MW	859,796
8	Total (Lines 1 thru 7)	5,613,643		61,379,476	8,597,958		-48,025,744

Schedule Page: 398 Line No.: 1 Column: b

"Scheduling, System Control and Dispatch" will be 0. Energy schedules will be recorded separately 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 and Flexible Ramping Product (FRP) charge codes 7070, 7078, 7088, 7071 , 7076 , 7077 , 7081, 7087.

Schedule Page: 398 Line No.: 4 Column: b

"Energy Imbalance" will be 0. Energy will be recorded separately 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

"Operating Reserve - Supplement" includes Non-Spinning Reserve at the ISO, charge code 6200, 6224, 6270, 6294, 6296 and 6720.

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	04/14/2021	End of 2020/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	12,498	16	18	11,534			964		
2	February	12,573	4	18	11,551			1,022		
3	March	12,212	5	19	11,102			1,110		
4	Total for Quarter 1				34,187			3,096		
5	April	15,145	24	18	14,047			1,098		
6	May	16,323	6	18	15,191			1,132		
7	June	18,491	10	17	17,078			1,413		
8	Total for Quarter 2				46,316			3,643		
9	July	20,382	31	18	18,926			1,456		
10	August	23,133	19	15	21,519			1,614		
11	September	23,066	6	16	21,498			1,568		
12	Total for Quarter 3				61,943			4,638		
13	October	21,695	1	16	20,092			1,603		
14	November	13,757	4	16	12,523			1,234		
15	December	12,865	28	18	11,768			1,097		
16	Total for Quarter 4				44,383			3,934		
17	Total Year to Date/Year				186,829			15,311		

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	04/14/2021	End of 2020/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	04/14/2021	End of 2020/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	2,814,130
4	Nuclear	4,984,004
5	Hydro-Conventional	2,028,165
6	Hydro-Pumped Storage	160,377
7	Other	226,178
8	Less Energy for Pumping	28,544
9	Net Generation (Enter Total of lines 3 through 8)	10,184,310
10	Purchases	56,591,078
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	7,140,929
17	Delivered	7,097,910
18	Net Transmission for Other (Line 16 minus line 17)	43,019
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	66,818,407

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	58,845,769
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,185,296
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	156,959
27	Total Energy Losses	3,630,383
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	66,818,407

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	5,182,522	374,850	12,398	16	1900
30	February	4,758,551	317,991	12,599	4	1900
31	March	4,752,854	249,845	12,137	5	1900
32	April	5,350,949	464,393	14,897	24	1800
33	May	6,676,956	289,269	16,189	6	1800
34	June	5,500,937	250,641	18,254	10	1800
35	July	5,581,390	435,482	20,186	31	1800
36	August	6,877,353	452,076	23,328	18	1600
37	September	6,350,891	411,960	22,972	6	1700
38	October	5,844,730	593,010	21,391	1	1700
39	November	4,798,384	277,873	13,488	4	1800
40	December	5,142,890	67,906	12,671	17	1900
41	TOTAL	66,818,407	4,185,296			

Schedule Page: 401 Line No.: 22 Column: b

Excludes 10,197,428 Direct access megawatt hours and 14,464,436 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	04/14/2021	End of 2020/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			49.00		
6	Net Peak Demand on Plant - MW (60 minutes)	645			49		
7	Plant Hours Connected to Load	3791			457		
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	306			5		
12	Net Generation, Exclusive of Plant Use - KWh	4984003736			20251144		
13	Cost of Plant: Land and Land Rights	1935457			0		
14	Structures and Improvements	661398583			3259411		
15	Equipment Costs	1413127316			66487110		
16	Asset Retirement Costs	0			0		
17	Total Cost	2076461356			69746521		
18	Cost per KW of Installed Capacity (line 17/5) Including	3103.8286			1423.3984		
19	Production Expenses: Oper, Supv, & Engr	15061543			353343		
20	Fuel	30990585			763757		
21	Coolants and Water (Nuclear Plants Only)	7649530			0		
22	Steam Expenses	4838079			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	6355330			0		
26	Misc Steam (or Nuclear) Power Expenses	21150896			737528		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2497535			132599		
30	Maintenance of Structures	1234813			-14228		
31	Maintenance of Boiler (or reactor) Plant	6389932			0		
32	Maintenance of Electric Plant	5718055			904195		
33	Maintenance of Misc Steam (or Nuclear) Plant	1857398			127210		
34	Total Production Expenses	103743696			3004404		
35	Expenses per Net KWh	0.0208			0.1484		
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	769144	0	0	202320	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	66888588	0	0	1031	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	40.292	0.000	0.000	3.775	0.000
41	Average Cost of Fuel per Unit Burned	0.000	40.292	0.000	0.000	3.775	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.602	0.000	0.000	3.660	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.006	0.000	0.000	0.038	0.000
44	Average BTU per KWh Net Generation	0.000	10322.000	0.000	0.000	10304.000	0.000

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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)	49.90			49.00		
6	Net Peak Demand on Plant - MW (60 minutes)	48			50		
7	Plant Hours Connected to Load	539			480		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	50			49		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	5			5		
12	Net Generation, Exclusive of Plant Use - KWh	17530876			22219853		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	3156191			4329915		
15	Equipment Costs	75072210			96293873		
16	Asset Retirement Costs	0			0		
17	Total Cost	78228401			100623788		
18	Cost per KW of Installed Capacity (line 17/5) Including	1567.7034			2053.5467		
19	Production Expenses: Oper, Supv, & Engr	356812			465226		
20	Fuel	879785			852969		
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	671519			713045		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	122728			123320		
30	Maintenance of Structures	-14228			-7572		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	683764			607233		
33	Maintenance of Misc Steam (or Nuclear) Plant	215243			209975		
34	Total Production Expenses	2915623			2964196		
35	Expenses per Net KWh	0.1663			0.1334		
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	195328	0	0	220055	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1038	0	0	1032	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	4.504	0.000	0.000	3.876	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.504	0.000	0.000	3.876	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.340	0.000	0.000	3.575	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.050	0.000	0.000	0.038	0.000
44	Average BTU per KWh Net Generation	0.000	11562.000	0.000	0.000	10218.000	0.000

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *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
1110.00			49.00			49.90			5
1107			50			47			6
23778			966			657			7
0			0			0			8
1110			49			50			9
0			0			0			10
38			5			5			11
2814129660			44363772			20077326			12
3218368			0			526947			13
59248505			2581018			3013852			14
767167092			80615403			81629153			15
0			0			0			16
829633965			83196421			85169952			17
747.4180			1697.8861			1706.8127			18
1291186			379740			374447			19
77517089			1833412			986875			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
27463530			639402			651405			26
0			0			0			27
0			0			0			28
2431111			122728			122728			29
1516397			-14228			-14228			30
0			0			0			31
9729901			810722			509213			32
850749			186483			164052			33
120799963			3958259			2794492			34
0.0429			0.0892			0.1392			35
GAS			GAS			GAS			36
GAS-MCF			GAS-MCF			GAS-MCF			37
0	20521669	0	0	438118	0	0	226714	0	38
0	1035	0	0	1025	0	0	1027	0	39
0.000	3.777	0.000	0.000	4.185	0.000	0.000	4.353	0.000	40
0.000	3.777	0.000	0.000	4.185	0.000	0.000	4.353	0.000	41
0.000	3.649	0.000	0.000	4.082	0.000	0.000	4.240	0.000	42
0.000	0.028	0.000	0.000	0.041	0.000	0.000	0.049	0.000	43
0.000	7549.000	0.000	0.000	10125.000	0.000	0.000	11592.000	0.000	44

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	0	0	11
0	0	0	12
8555	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
8555	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

									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 Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 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.

Schedule Page: 402 Line No.: 5 Column: b

Palo Verde: Data represents 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 to 49 MW by 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 to 49 MW by 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 to 49 MW 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 needed. 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 to 49 MW by 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 to 49 MW by 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	04/14/2021	End of 2020/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)	88.35	66.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	86	65
7	Plant Hours Connect to Load	7,247	8,363
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	88	67
10	(b) Under the Most Adverse Oper Conditions	88	67
11	Average Number of Employees	9	9
12	Net Generation, Exclusive of Plant Use - Kwh	164,443,065	117,366,728
13	Cost of Plant		
14	Land and Land Rights	0	1,344
15	Structures and Improvements	68,991,647	19,511,730
16	Reservoirs, Dams, and Waterways	8,177,353	5,502,548
17	Equipment Costs	34,851,769	28,196,714
18	Roads, Railroads, and Bridges	1,939,809	1,522,621
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	113,960,578	54,734,957
21	Cost per KW of Installed Capacity (line 20 / 5)	1,289.8764	823.0821
22	Production Expenses		
23	Operation Supervision and Engineering	146,827	110,515
24	Water for Power	223,024	167,868
25	Hydraulic Expenses	179,881	121,862
26	Electric Expenses	98,062	76,918
27	Misc Hydraulic Power Generation Expenses	1,448,557	1,015,345
28	Rents	55,958	42,119
29	Maintenance Supervision and Engineering	303,710	228,599
30	Maintenance of Structures	910,172	162,342
31	Maintenance of Reservoirs, Dams, and Waterways	199,926	142,131
32	Maintenance of Electric Plant	375,321	425,853
33	Maintenance of Misc Hydraulic Plant	92,824	52,062
34	Total Production Expenses (total 23 thru 33)	4,034,262	2,545,614
35	Expenses per net KWh	0.0245	0.0217

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	04/14/2021	End of 2020/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)	0.00	110.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	99
7	Plant Hours Connect to Load	0	5,861
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	99
10	(b) Under the Most Adverse Oper Conditions	0	99
11	Average Number of Employees	0	9
12	Net Generation, Exclusive of Plant Use - Kwh	-204,378	215,127,280
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	2,667,236
16	Reservoirs, Dams, and Waterways	0	6,377,484
17	Equipment Costs	0	19,463,558
18	Roads, Railroads, and Bridges	0	13,269
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	28,521,547
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	259.2868
22	Production Expenses		
23	Operation Supervision and Engineering	0	182,806
24	Water for Power	0	277,676
25	Hydraulic Expenses	238	194,637
26	Electric Expenses	133	110,011
27	Misc Hydraulic Power Generation Expenses	0	1,649,160
28	Rents	0	69,670
29	Maintenance Supervision and Engineering	0	378,134
30	Maintenance of Structures	3,952	169,200
31	Maintenance of Reservoirs, Dams, and Waterways	9,959	222,434
32	Maintenance of Electric Plant	1,063	278,005
33	Maintenance of Misc Hydraulic Plant	34,559	42,899
34	Total Production Expenses (total 23 thru 33)	49,904	3,574,632
35	Expenses per net KWh	0.0000	0.0166

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)	40.18	190.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	177
7	Plant Hours Connect to Load	8,261	4,589
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	36	178
10	(b) Under the Most Adverse Oper Conditions	36	178
11	Average Number of Employees	6	9
12	Net Generation, Exclusive of Plant Use - Kwh	100,912,659	320,641,959
13	Cost of Plant		
14	Land and Land Rights	266,104	161,028
15	Structures and Improvements	2,740,195	2,819,260
16	Reservoirs, Dams, and Waterways	36,167,865	27,782,599
17	Equipment Costs	18,409,320	36,982,175
18	Roads, Railroads, and Bridges	4,806,302	525,860
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	62,389,786	68,270,922
21	Cost per KW of Installed Capacity (line 20 / 5)	1,552.7572	359.3206
22	Production Expenses		
23	Operation Supervision and Engineering	210,714	315,756
24	Water for Power	339,822	479,622
25	Hydraulic Expenses	168,056	346,910
26	Electric Expenses	254,133	173,474
27	Misc Hydraulic Power Generation Expenses	2,005,749	2,829,157
28	Rents	170,437	120,339
29	Maintenance Supervision and Engineering	191,283	653,141
30	Maintenance of Structures	59,113	311,596
31	Maintenance of Reservoirs, Dams, and Waterways	155,189	353,936
32	Maintenance of Electric Plant	52,577	-173,134
33	Maintenance of Misc Hydraulic Plant	29,911	82,940
34	Total Production Expenses (total 23 thru 33)	3,636,984	5,493,737
35	Expenses per net KWh	0.0360	0.0171

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	04/14/2021	End of 2020/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	8,458,115	0
16	Reservoirs, Dams, and Waterways	132,673,803	0
17	Equipment Costs	2,468,272	0
18	Roads, Railroads, and Bridges	1,780,692	0
19	Asset Retirement Costs	0	2,830,642
20	TOTAL cost (Total of 14 thru 19)	148,924,785	2,830,642
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	11.25	5
62	10	11	6
5,905	4,818	7,119	7
			8
71	11	11	9
71	11	11	10
9	9	2	11
94,636,208	16,200,999	13,927,076	12
			13
0	34,762	75,235	14
4,581,071	2,967,770	9,428,524	15
3,384,931	3,511,200	422,387	16
23,604,930	9,469,603	17,036,472	17
3,103,126	278,037	0	18
0	0	0	19
34,674,058	16,261,372	26,962,618	20
462.3208	1,505.6826	2,396.6772	21
			22
124,641	17,948	58,885	23
189,324	27,263	95,147	24
151,820	24,189	48,650	25
83,358	14,311	0	26
1,128,610	166,690	632,049	27
47,502	6,840	47,721	28
257,819	37,126	102,244	29
176,313	116,508	1,099	30
155,754	43,795	156,881	31
172,454	152,578	45,394	32
37,936	6,245	14,850	33
2,525,531	613,493	1,202,920	34
0.0267	0.0379	0.0864	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	04/14/2021	End of 2020/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
174.45	100.00	26.28	5
177	99	27	6
6,833	6,740	8,707	7
			8
175	100	26	9
175	100	26	10
9	9	6	11
404,914,329	215,538,365	156,790,966	12
			13
6,142	104,451	120,432	14
9,266,171	3,217,929	6,994,099	15
21,043,984	16,375,324	37,994,888	16
60,687,552	19,279,997	20,712,614	17
3,592,882	377,829	1,532,742	18
0	0	0	19
94,596,731	39,355,530	67,354,775	20
542.2570	393.5553	2,562.9671	21
			22
289,914	166,188	137,819	23
440,369	252,433	222,263	24
325,118	200,520	125,749	25
165,877	109,238	94,230	26
2,627,727	1,520,445	1,115,700	27
110,490	63,336	111,476	28
599,686	343,758	125,110	29
344,977	223,226	57,442	30
364,253	267,522	24,910	31
412,760	328,157	38,101	32
106,575	43,620	50,163	33
5,787,746	3,518,443	2,102,963	34
0.0143	0.0163	0.0134	35

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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. 1388 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
246,193	992,853	465,072	15
11,393,498	14,516,427	11,911,183	16
2,711,970	18,267	7,505,562	17
0	68,727	194,511	18
0	0	0	19
14,359,405	15,596,274	20,217,253	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	04/14/2021	End of 2020/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. 1389 Plant Name: Rush Creek (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
35,409,101	0	0	12
			13
72,508	0	0	14
1,602,925	0	0	15
3,410,378	0	0	16
13,616,926	0	0	17
354,909	0	0	18
0	0	0	19
19,057,646	0	0	20
0.0000	0.0000	0.0000	21
			22
68,097	0	0	23
110,032	0	0	24
45,839	0	0	25
0	0	0	26
752,680	0	0	27
55,186	0	0	28
118,239	0	0	29
14,927	0	0	30
72,199	0	0	31
131,439	0	0	32
14,177	0	0	33
1,382,815	0	0	34
0.0391	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 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: 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 Power 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: b

Borel Licensed Project No. 382

Plant is retired.

Schedule Page: 406.1 Line No.: 1 Column: b

Borel Licensed Project No. 382

There is no KWH generated during the plan year.

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

Hydro Plant Borel was retired in 2017. Currently in the process of surrendering the FERC license.

Schedule Page: 406.2 Line No.: -2 Column: d

Poole Plant Reservoir Facilities

FERC Licensed Project No. 1388 - Poole Plant

Schedule Page: 406.2 Line No.: -1 Column: d

Poole Plant Res Fac

FERC Licensed Project Number 1388 and 1390 - Poole Plant

Operated by remote control from Poole Plant. Including Saddlebag, Tioga, and Rhinedollar reservoirs. Expenses incurred at Poole Reservoir Failities are allocated to Poole Plant.

Schedule Page: 406.2   Line No.: -1   Column: e

Rush Creek Res Fac

Includes Rush Meadows Reservoir, Gem Lake and Agnew Lake. Expenses incurred at Rush Creek Reservoir Facilities are allocated to Rush Creek Plant.

Schedule Page: 406.2   Line No.: -1   Column: f

Bishop Plant Res Fac

Includes Intake 2 Reservoir, South Lake Sabrina Lake, Birch, and McGee Diversions and miscellaneous Bishop Creek water rights. Expenses incurred at Bishop Plant Reservoir Facilities are allocated at the end of the year to Bishop Creek Plants.

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: 406.3   Line No.: 20   Column: b

Big Creek Water Collection Facilities

Expenses incurred at Brig 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 (Reservoir), Shaver Lake (Reservoir), Florence Lake, Lake Thomas A. Edison, Mammoth Pool Lake and miscellaneous 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	04/14/2021	End of 2020/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)	199
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	200
6	Plant Hours Connect to Load While Generating	2,085
7	Net Plant Capability (in megawatts)	200
8	Average Number of Employees	9
9	Generation, Exclusive of Plant Use - Kwh	160,377,147
10	Energy Used for Pumping	28,544,243
11	Net Output for Load (line 9 - line 10) - Kwh	131,832,904
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	50,918,541
15	Reservoirs, Dams, and Waterways	161,242,182
16	Water Wheels, Turbines, and Generators	31,487,822
17	Accessory Electric Equipment	16,010,132
18	Miscellaneous Powerplant Equipment	6,834,785
19	Roads, Railroads, and Bridges	2,700,062
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	269,193,524
22	Cost per KW of installed cap (line 21 / 4)	1,347.3149
23	Production Expenses	
24	Operation Supervision and Engineering	332,043
25	Water for Power	504,588
26	Pumped Storage Expenses	364,773
27	Electric Expenses	191,748
28	Misc Pumped Storage Power generation Expenses	3,009,990
29	Rents	126,546
30	Maintenance Supervision and Engineering	686,829
31	Maintenance of Structures	361,065
32	Maintenance of Reservoirs, Dams, and Waterways	370,056
33	Maintenance of Electric Plant	403,139
34	Maintenance of Misc Pumped Storage Plant	97,431
35	Production Exp Before Pumping Exp (24 thru 34)	6,448,208
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	6,448,208
38	Expenses per KWh (line 37 / 9)	0.0402

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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
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Schedule Page: 408   Line No.: 1   Column: b

Operating by remote control from Big Creek No. 3 Hydroelectric Generating Plant.

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

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 $0.03413 ($6,448,208/188,921,390 KWh).

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	Other Production					
2	Santa Catalina Island					
3	Unit 7 Diesel	1957	1.00			
4	Unit 8 Diesel	1964	1.50			
5	Unit 10 Diesel	1966	1.10			
6	Unit 12 Diesel	1976	1.60			
7	Unit 14 Diesel	1976	1.40			
8	Unit 15 Diesel	1994	2.80			
9	Micro-Turbines	2011	1.50			
10	TOTAL		10.90	5.2	27,417,559	82,367,579
11						
12						
13	Hydro					
14	Kaweah No.1	1929	2.25		-69,082	23,986,186
15	Kaweah No.2	1929	1.80	0.7	2,501,414	9,996,539
16	Kaweah No.3	1913	4.80	4.4	13,097,715	12,784,214
17	Santa Ana No.1 & 2	1899	3.20	1.2	466,991	5,698,574
18	Santa Ana No.3	1999	3.10	1.7	1,872,395	25,092,220
19	Lower Tule	1909	2.52		-100,502	38,000,423
20	Mill Creek No.1	1893	0.80	0.9	4,367,597	2,244,218
21	Mill Creek No. 2 & 3	1903	3.00	1.9	4,417,759	3,400,106
22	Lytle Creek	1904	0.50	0.4	2,446,122	1,397,453
23	Fontana	1917	2.95	1.0	5,996,551	779,866
24	Sierra	1922	0.48	0.6	3,165,721	800,007
25	Ontario No.1	1902	0.60	0.7	4,369,419	5,887,973
26	Ontario No.2	1963	0.32	0.3	1,589,743	1,441,596
27	Bishop Creek No. 2	1908	7.32	8.0	28,675,704	19,480,526
28	Bishop Creek No. 3	1913	7.84	7.5	28,056,432	10,201,041
29	Bishop Creek No. 4	1905	7.96	8.6	42,962,451	28,811,848
30	Bishop Creek No. 5	1919	4.53	3.9	13,690,866	6,976,317
31	Bishop Creek No. 6	1913	1.60	2.0	10,420,971	6,982,542
32	San Gorgonio No. 1 & 2	1923				7,428,470
33	Lundy	1911	3.00	2.6	4,532,507	6,826,909
34						
35						
36						
37	Other:					
38	Solar Photovoltaic					
39	SC-CHINO-SOL	2009	1.00	0.7	721,921	6,990,125
40	SC-RIALTO3-SOL	2010	1.00	0.7	569,824	8,298,038
41	SC-REDLND5-SOL	2010	2.50	2.0	2,661,971	28,070,660
42	SC-ONTAR6-SOL	2011	2.00	1.6	2,454,133	20,425,472
43	SC-REDLND7-SOL	2010	2.50	1.7	2,305,099	26,902,880
44	SC-ONTAR8-SOL	2010	2.00	1.4	1,939,446	23,428,222
45	SC-ONTAR9-SOL	2011	1.00	0.9	1,190,729	11,875,973
46	SC-ETWIND10-SOL	2011	1.50	1.3	1,637,334	18,507,679

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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-REDLND11-SOL	2011	3.50	2.6	3,260,250	41,251,684
2	SC-ONTAR12-SOL	2010	0.50	0.5	446,991	6,616,809
3	SC-REDLND13-SO	2011	3.50	3.1	3,703,293	39,192,179
4	SC-ETWIND15-SOL	2011	3.50	2.3	3,764,677	20,044,961
5	SC-REDLND16-SO	2011	1.50	0.7	740,159	17,053,816
6	SC-ETWIND17-SOL	2011	3.50	2.4	3,578,575	37,311,345
7	SC-ETWIND18-SOL	2011	1.50	1.2	1,502,133	17,325,498
8	SC-REDLND22-SO	2010	2.00	1.2	1,725,516	12,205,272
9	SC-ETWIND23-SOL	2011	2.50	2.4	3,803,943	31,066,364
10	SC-ETWIND26-SOL	2011	6.00	5.0	7,644,470	70,760,854
11	SC-ETWIND27-SOL	2012	2.00	1.5	1,397,311	9,483,921
12	SC-VISTA28-SOL	2011	3.50	2.6	3,710,691	39,380,683
13	SC-ONTAR32-SOL	2011	1.50	1.0	1,461,335	13,520,198
14	SC-ONTAR33-SOL	2011	1.00	0.9	1,409,492	12,166,646
15	SC-VESTAL42-SOL	2010	5.00	4.6	6,673,045	45,772,850
16	SC-VALLY44-SOL	2012				69,670,679
17	SC-REDLND48-SOL	2013	5.00	3.6	6,224,395	19,557,598
18						
19	TOTAL SOLAR VOLTAIC				64,526,730	646,880,403
20						
21	Environmental Mitigation Services					
22	IT IMM Costs					
23	UC Santa Barbara Fuel Cell	2012			1,356,253	
24	CS San Bernardino Fuel Cell	2013			8,434,687	
25	Clean Air Act Settlement/Ash Pond Cleanup Effort					
26	Backup Generator Costs for the Creek Fire Rest..					
27						
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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	04/14/2021	End of 2020/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
				Diesel		3
				Diesel		4
				Diesel		5
				Diesel		6
				Diesel		7
				Diesel		8
				Propane		9
7,556,659	7,136,231	4,962,945	1,122,265		3,469	10
						11
						12
						13
10,660,527	254,742		171,603			14
5,553,633	242,702		230,797			15
2,663,378	522,226		166,716			16
1,780,804	318,966		240,701			17
8,094,265	311,778		245,310			18
15,079,533	254,194		46,345			19
2,805,273	130,638		37,385			20
1,133,369	304,025		261,828			21
2,794,906	101,258		201,627			22
264,361	294,248		153,241			23
1,666,681	82,608		33,008			24
9,813,288	88,976		46,577			25
4,504,988	62,477		18,068			26
2,661,274	1,288,673		223,613			27
1,301,153	655,390		186,744			28
3,619,579	623,252		239,223			29
1,540,026	359,285		146,736			30
4,364,089	115,418		61,828			31
	63,303		4,352,842			32
2,275,636	308,552		236,403			33
						34
						35
						36
						37
						38
6,990,125	48,770		4,019			39
8,298,038	56,580		7,864			40
11,228,264	114,094		12,366			41
10,212,736	91,488		10,150			42
10,761,152	112,723		22,352			43
11,714,111	94,582		12,010			44
11,875,973	50,434		4,019			45
12,338,452	71,513		6,029			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.
11,786,195	162,777		18,423			1
13,233,618	25,658		2,010			2
11,197,765	158,869		16,405			3
5,727,132	170,491		82,149			4
11,369,211	85,809		11,060			5
10,660,384	171,509		16,753			6
11,550,332	69,765		11,474			7
6,102,636	87,252		9,273			8
12,426,545	124,647		13,204			9
11,793,476	275,517		-19,523			10
4,741,961	114,395		11,957			11
11,251,624	163,065		21,353			12
9,013,465	78,996		1,601			13
12,166,646	41,544		4,752			14
9,154,570	271,747		85,147			15
			12			16
3,911,520	243,878		20,097			17
						18
	2,886,105		384,956			19
						20
	10,150,056					21
	1,218,351					22
	93,873	60,849			5,717	23
	40,593	468,546	397,321		5,568	24
	368,847					25
	4,157,128					26
						27
						28
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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 Creek 1, 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.: 18 Column: a
Licensed Projects:
Santa Ana #3 Project No. 1933

SCE owns and operates 5 non-licensed powerhouses: Mill Creek 1, 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 Creek 1, 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.: 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 Creek 1, 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.: 22 Column: a
Licensed Projects:
Lytle Creek Project No. 1932

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 27 Column: a
Licensed Project:
Bishop Creek # 2 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 28 Column: a
Licensed Project:
Bishop Creek # 3 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 29 Column: a
Licensed Project:
Bishop Creek # 4 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 30 Column: a
Licensed Project:
Bishop Creek # 5 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 31   Column: a

Licensed Project:
Bishop Creek #6 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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.: 32   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.: 32   Column: f

Reflects Asset Retirement Costs.

Schedule Page: 410   Line No.: 32   Column: g

N/A

Schedule Page: 410   Line No.: 33   Column: a

Licensed Project:
Lundy Project No. 1390

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, 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: 410.1   Line No.: 16   Column: f

Plant was decommissioned in 2019.

Schedule Page: 410.1   Line No.: 19   Column: a

Solar sites do not have a reliable way to measure plant use.

All Solar sites are commercially certified by CAISO.

Schedule Page: 410.1   Line No.: 25   Column: a

Clean Air Act Settlement and Ash Pond Cleanup Efforts-Four Corner

Schedule Page: 410.1   Line No.: 26   Column: a

Back up generator costs for the Creek Fire restoration efforts.

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	800 KV LINES							
2	SYLMAR	CELILO (CA)	800.00	800.00	ST	14.20		
3	SYLMAR	CELILO (CA)	800.00	800.00	ST	149.59		
4	SYLMAR	CELILO (CA)	800.00	800.00	UG	3.68		
5	SYLMAR	CELILO (CA)	800.00	800.00	UG	0.61		4
6	SYLMAR	CELILO (NV)	800.00	800.00	ST	144.86		1
7								
8	500 KV LINES							
9	MIDWAY	VINCENT NO.1 & 2	500.00	500.00	ST	225.49		2
10	LUGO	VINCENT NO 1 & 2	500.00	500.00	ST	94.39		2
11	SANTA CLARA	VINCENT	500.00	500.00	ST	0.24		1
12	SANTA CLARA	VINCENT	500.00	500.00	ST	27.24		
13	LUGO	MIRA LOMA NO 1, 2, & 3	500.00	500.00	ST	83.09	13.41	3
14	DEVERS	PALO VERDE ARIZONA	500.00	500.00	ST	112.05		1
15	DEVERS	VALLEY	500.00	500.00	ST	41.60		1
16	MIRA LOMA	SERRANO NO 1 & 2	500.00	500.00	ST	26.98	1.77	2
17	LUGO	MOHAVE/NEVADA	500.00	500.00	ST	9.85		1
18	EL DORADO	LUGO (CA)	500.00	500.00	ST	150.67		1
19	EL DORADO	LUGO (NV)	500.00	500.00	ST	26.51		1
20	SERRANO	VALLEY	500.00	500.00	ST	40.52		1
21	LUGO	MOHAVE (CA)	500.00	500.00	ST	165.96		1
22	EL DORADO	MOHAVE (NV)	500.00	500.00	ST	19.93		1
23	EL DORADO	MOENKOPI (NV)	500.00	500.00	ST	29.65		1
24	LUGO	VICTORVILLE	500.00	500.00	ST	7.57		1
25	MIDWAY	VINCENT NO.3	500.00	500.00	ST	52.62		1
26	DEVERS	PALO VERDE CALIF	500.00	500.00	ST	126.45		1
27	MIRA LOMA	VINCENT	500.00	500.00	SP	9.89		
28	MIRA LOMA	VINCENT	500.00	500.00	ST	57.58		
29	MIRA LOMA	VINCENT	500.00	500.00	UG	3.78		1
30	MIRA LOMA	RANCHO VISTA	500.00	500.00	SP	0.48		
31	MIRA LOMA	RANCHO VISTA	500.00	500.00	ST	2.71		
32	LAUGHLIN	MOHAVE	500.00	500.00	ST	0.22		2
33	LAUGHLIN	MOHAVE-NO.1	500.00	500.00	ST	0.11		
34	PARDEE	VARIOUS	500.00	500.00	ST	84.07	12.78	
35	COGE RENEWABLES	VARIOUS	500.00	500.00	SP	0.13		
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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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	500 KV LINES CONT'D							
2	COGE RENEWABLES	VARIOUS	500.00	500.00	ST	0.25	2.45	
3	COGEN RENEWABLES	VARIOUS	500.00	500.00	UG	0.48		4
4	COGEN RENEWABLES	VARIOUS	500.00	500.00	UG	69.90	2.57	
5	COGE RENEWABLES	VARIOUS	500.00	500.00	UG	0.08		
6	COGEN RENEWABLES	VARIOUS	500.00	500.00	UG	8.55		
7	COGE RENEWABLES	VARIOUS	500.00	500.00	UG	1.06		
8	COGEN RENEWABLES	VARIOUS	500.00	500.00	UG	0.12		
9	COGEN RENEWABLES	VARIOUS	500.00	500.00	UG	17.06		
10	COGE RENEWABLES	VARIOUS	500.00	500.00	UG	0.34	2.40	
11	COGE RENEWABLES	VARIOUS	500.00	500.00	UG	0.30		
12	ELDORADO	MEAD NO.2/NEVADA	500.00	500.00	ST	15.29		1
13	ELDORADO	MEAD NO.2/NEVADA	500.00	500.00	ST	15.35		1
14	RIO HONDO	VINCENT NO.2	500.00	500.00	ST	20.57		1
15								
16	220 KV LINES							
17	MAGUNDEN	PASTORIA NO.1	220.00	220.00	ST	29.86		1
18	MAGUNDEN	PASTORIA NO.2	220.00	220.00	ST	29.23	0.64	1
19	MAGUNDEN	PASTORIA NO.3	220.00	220.00	ST	29.86		1
20	BIG CREEK NO 3	MAMMOTH POOL	220.00	220.00	ST	6.50		1
21	MESA	SYLMAR	220.00	220.00	ST	6.13		1
22	EAGLE ROCK	MESA	220.00	220.00	ST	2.54		1
23	MESA	REDONDO	220.00	220.00	ST	14.22		1
24	CENTER	MESA	220.00	220.00	SP	0.36		
25	CENTER	MESA	220.00	220.00	ST	47.52	39.62	
26	CENTER	MESA	220.00	220.00	ST	18.49		2
27	HINSON	LIGHTHIPE	220.00	220.00	ST	0.43	0.53	1
28	HINSON	LIGHTHIPE	220.00	220.00	ST	0.11	5.27	1
29	HINSON	LA FRESA	220.00	220.00	ST	0.07	8.76	1
30	CENTER	OLINDA	220.00	220.00	ST	3.11	10.41	
31	CENTER	OLINDA	220.00	220.00	ST	1.21	4.05	1
32	ALAMITOS	CENTER	220.00	220.00	ST	11.47		1
33	MIRA LOMA	WALNUT	220.00	220.00	ST	27.65		1
34	DEVERS	VALLEY NO.1	220.00	220.00	SP	0.12		1
35	DEVERS	VALLEY NO.1	220.00	220.00	ST	41.63		1
36					TOTAL	12,178.52	2,595.25	1,268

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1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	220 KV LINES CONT'D							
2	CALDWELL	VICTOR	220.00	220.00	SP	1.64		1
3	CALDWELL	VICTOR	220.00	220.00	SP	5.97		
4	BAILEY	PARDEE	220.00	220.00	ST	0.36		1
5	BAILEY	PARDEE	220.00	220.00	ST	26.61		
6	COGEN RENEWABLES	VARIOUS	220.00	220.00	ST	0.03		
7	ANTELOPE	MAGUNDEN NO.1	220.00	220.00	ST	59.25		1
8	MOORPARK	PARDEE NO.1	220.00	220.00	ST	25.96		1
9	MOORPARK	PARDEE NO.2	220.00	220.00	ST	25.99		1
10	MOORPARK	PARDEE NO.3	220.00	220.00	ST	0.15	25.84	1
11	ANTELOPE	PARDEE	220.00	220.00	SP	0.14		1
12	ANTELOPE	PARDEE	220.00	220.00	ST	0.69		1
13	ANTELOPE	PARDEE	220.00	220.00	ST	25.70		1
14	ANTELOPE	PARDEE	220.00	220.00	WP	0.05		1
15	PARDEE	SYLMAR NO 1 & 2	220.00	220.00	ST	11.62	11.35	2
16	PARDEE	VINCENT NO.2	220.00	220.00	SP	2.13		
17	PARDEE	VINCENT NO.2	220.00	220.00	ST	2.15		1
18	PARDEE	VINCENT	220.00	220.00	ST	31.72	9.47	1
19	PARDEE	VINCENT	220.00	220.00	ST	22.89	1.04	1
20	PARDEE	VINCENT	220.00	220.00	WP	0.34		1
21	ANTELOPE	MAGUNDEN NO.2	220.00	220.00	ST	59.27		1
22	DEVERS	VARIOUS	220.00	220.00	SP	0.61		3
23	DEVERS	VARIOUS	220.00	220.00	ST	8.11		
24	DEVERS	VARIOUS	220.00	220.00	ST	47.24	39.72	
25	DEVERS	VARIOUS	220.00	220.00	WH	9.05		
26	DEVERS	VARIOUS	220.00	220.00	WH	15.57		
27	SERRANO	VILLA PARK NO.1 & 2	220.00	220.00	ST	3.39	3.11	2
28	DEVERS	VALLEY NO.2	220.00	220.00	SP	0.12		1
29	DEVERS	VALLEY NO.2	220.00	220.00	ST	41.63		1
30	MIRA LOMA	VISTA NO. 2	220.00	220.00	ST	0.22	15.25	1
31	EAGLE ROCK	SYLMAR	220.00	220.00	SP	0.38		
32	EAGLE ROCK	SYLMAR	220.00	220.00	ST	0.44	24.65	1
33	EAGLE ROCK	PARDEE	220.00	220.00	SP	0.04		
34	PARDEE	VINCENT	220.00	220.00	SP	0.12		
35	EAGLE ROCK	PARDEE	220.00	220.00	SP	0.97		
36					TOTAL	12,178.52	2,595.25	1,268

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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	220 KV LINES CONT'D							
2	EAGLE ROCK	PARDEE	220.00	220.00	ST	41.90	0.88	
3	PARDEE	VINCENT	220.00	220.00	ST	88.65	6.05	
4	PARDEE	VINCENT	220.00	220.00	ST	14.49		1
5	EAGLE ROCK	PARDEE	220.00	220.00	ST	7.00		
6	PARDEE	VINCENT	220.00	220.00	WH	1.17		2
7	SANTA CLARA	VINCENT	220.00	220.00	ST	0.74	40.08	
8	SANTA CLARA	VINCENT	220.00	220.00	ST	29.69		1
9	RIO HONDO	VINCENT NO.2	220.00	220.00	ST	9.14		
10	RIO HONDO	VINCENT NO.2	220.00	220.00	ST	20.89		1
11	PARDEE	VARIOUS	220.00	220.00	SP	0.34		
12	PARDEE	VARIOUS	220.00	220.00	ST	0.50	0.11	
13	PARDEE	VARIOUS	220.00	220.00	WH	1.33	0.07	
14	PARDEE	VARIOUS	220.00	220.00	WH	3.81		
15	PARDEE	VARIOUS	220.00	220.00	WH	45.04	12.02	
16	PARDEE	VARIOUS	220.00	220.00	WH	246.68		
17	PARDEE	VARIOUS	220.00	220.00	WH	0.07		13
18	PARDEE	VARIOUS	220.00	220.00	WH	12.08		
19	DEVERS	VARIOUS	220.00	220.00	ST	79.09	19.49	
20	DEVERS	VARIOUS	220.00	220.00	UG	0.04		
21	DEVERS	VARIOUS	220.00	220.00	WH	4.77		3
22	DEVERS	VARIOUS	220.00	220.00	WH	10.02	44.30	
23	DEVERS	VARIOUS	220.00	220.00	WH	235.50		
24	ANTELOPE	VARIOUS	220.00	220.00	ST	85.04	10.83	
25	RIO HONDO	VINCENT NO 1	220.00	220.00	ST	27.70	4.66	2
26	CHINO	VARIOUS	220.00	220.00	ST	85.39	83.81	3
27	COACHELLA VALLEY	DEVERS	220.00	220.00	ST	0.10	0.28	1
28	BIG CREEK NO.3	BIG CREEK NO.4	220.00	220.00	ST	5.79		1
29	BIG CREEK 3	SPRINGVILLE	220.00	220.00	ST	76.70		1
30	LAGUNA BELL	VARIOUS	220.00	220.00	SP	0.15		
31	LAGUNA BELL	VARIOUS	220.00	220.00	ST	46.31	31.63	
32	LAGUNA BELL	VARIOUS	220.00	220.00	ST	17.08		3
33	HINSON	VARIOUS	220.00	220.00	ST	6.84	6.73	2
34	HINSON	VARIOUS	220.00	220.00	ST	8.82		2
35	EL NIDO	VARIOUS	220.00	220.00	SP	0.18		
36					TOTAL	12,178.52	2,595.25	1,268

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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)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	220 KV LINES CONT'D							
2	EL NIDO	VARIOUS	220.00	220.00	ST	8.92	22.77	
3	EL NIDO	VARIOUS	220.00	220.00	UG	0.48		7
4	EL NIDO	VARIOUS	220.00	220.00	UG	11.36	0.41	
5	EL NIDO	VARIOUS	220.00	220.00	UG	4.59	8.76	
6	EL NIDO	VARIOUS	220.00	220.00	UG	3.69	3.69	
7	PISGAH NO 2	VARIOUS	220.00	220.00	ST	0.07		
8	PISGAH NO 2	VARIOUS	220.00	220.00	ST	139.30		
9	PISGAH NO 2	VARIOUS	220.00	220.00	WH	0.72		2
10	MIRA LOMA	VARIOUS	220.00	220.00	SP	0.05		
11	MIRA LOMA	VARIOUS	220.00	220.00	ST	8.10	41.69	
12	MIRA LOMA	VARIOUS	220.00	220.00	ST	0.14		
13	MIRA LOMA	VARIOUS	220.00	220.00	ST	7.58	6.90	
14	MIRA LOMA	VARIOUS	220.00	220.00	ST	19.56	2.16	4
15	ALAMITOS	VARIOUS	220.00	220.00	SP	0.06		
16	ALAMITOS	VARIOUS	220.00	220.00	ST	20.90	26.42	
17	ALAMITOS	VARIOUS	220.00	220.00	ST	0.16	9.60	4
18	BIG CREEK 4	SPRINGVILLE	220.00	220.00	ST	83.52		1
19	MOORPARK	VARIOUS	220.00	220.00	ST	147.12	83.38	
20	MOORPARK	VARIOUS	220.00	220.00	ST	48.53	43.78	6
21	CIMA	PISGAH (NV)	220.00	220.00	ST	57.54	0.63	1
22	KRAMER	VARIOUS	220.00	220.00	SP	0.05		
23	KRAMER	VARIOUS	220.00	220.00	ST	97.45	47.38	4
24	PEARBLOSSOM	VINCENT	220.00	220.00	ST	0.88		
25	PEARBLOSSOM	VINCENT	220.00	220.00	WH	12.25		1
26	ELLIS	SANTIAGO NO 1 & 2	220.00	220.00	SP	9.29	9.29	
27	ELLIS	SANTIAGO NO 1 & 2	220.00	220.00	ST	5.64	5.28	2
28	BIG CREEK NO 2	BIG CREEK NO.8	220.00	220.00	ST	3.40		
29	BIG CREEK NO 2	BIG CREEK NO.8	220.00	220.00	ST	5.62		1
30	BIG CREEK	VARIOUS	220.00	220.00	SP	0.25		
31	BIG CREEK	VARIOUS	220.00	220.00	ST	246.46	0.23	
32	BIG CREEK	VARIOUS	220.00	220.00	ST	5.67		7
33	BIG CREEK 1	EASTWOOD	220.00	220.00	SP	0.10		
34	BIG CREEK 1	EASTWOOD	220.00	220.00	ST	4.55		1
35	RANCHO VISTA	LUGO	220.00	220.00	ST	32.15		2
36					TOTAL	12,178.52	2,595.25	1,268

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	220 KV LINES CONT'D							
2	COLORADO RIVER	RED BLUFF NO. 1 & 2	220.00	220.00	SP	0.29		
3	COLORADO RIVER	RED BLUFF NO. 1 & 2	220.00	220.00	ST	63.91		
4	DEVERS	RED BLUFF NO. 1 & 2	220.00	220.00	ST	161.00		4
5	CALDWELL	VICTOR	220.00	220.00	SP	1.64		
6	CALDWELL	VICTOR	220.00	220.00	ST	5.97		1
7	ANTELOPE	WINDHUB	220.00	220.00	ST	25.44		1
8	ANTELOPE	WHIRLWIND	220.00	220.00	ST	14.49		1
9	WHIRLWIND	WINDHUB	220.00	220.00	ST	16.13		1
10	ANTELOPE	VINCENT NO.2	220.00	220.00	ST	17.41		1
11	ANTELOPE	VINCENT NO.1	220.00	220.00	ST	17.40		1
12	KRAMER	VICTOR NO.1	220.00	220.00	ST	37.50		1
13	LUGO	VICTORVILLE	220.00	220.00	ST	7.57		1
14	VINCENT	WHIRLWIND	220.00	220.00	SP	0.18		
15	VINCENT	WHIRLWIND	220.00	220.00	ST	36.17		1
16	DEVERS	VISTA NO 1	220.00	220.00	SP	0.61		1
17	DEVERS	SAN BERNARDINO NO 2	220.00	220.00	ST	8.11		
18	DEVERS	VISTA NO 2	220.00	220.00	ST	0.36	44.66	1
19	DEVERS	VISTA NO 1	220.00	220.00	ST	4.99		1
20	DEVERS	SAN BERNARDINO NO 2	220.00	220.00	WH	9.05		1
21	DEVERS	VISTA NO 1	220.00	220.00	WH	15.57		1
22	DEVERS	SAN BERNARDINO NO 2	220.00	220.00	WH	26.22		2
23	INLAND EMPIRE	VALLEY	220.00	220.00	ST	1.27		1
24	COLORADO RIVER	PALO VERDE	220.00	220.00	ST	128.88		1
25	MIDWAY	WHIRLWIND	220.00	220.00	ST	73.72		1
26	RECTOR	SPRINGVILLE	220.00	220.00	ST	47.50		3
27	MESA	VINCENT-NO.2	220.00	220.00	SP	0.19		
28	MESA	VINCENT-NO.2	220.00	220.00	ST	17.97		
29	MESA	VINCENT-NO.2	220.00	220.00	WH	0.48		
30	HIGHWIND	MANDIBLE	220.00	220.00	ST	0.48		
31	ELDORADO	IVANPAH	220.00	220.00	ST	34.42		1
32	BARRE	VILLA PARK	220.00	220.00	ST	8.95		1
33	LUGO	VICTOR NO.3	220.00	220.00	ST	10.40		
34	LUGO	VICTOR NO.4	220.00	220.00	ST	10.40		
35	LEBEC	PASTORIA	220.00	220.00	ST	0.02		1
36					TOTAL	12,178.52	2,595.25	1,268

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	220 KV LINES CONT'D							
2	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	ST	10.98		
3	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	ST	52.06		
4	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	ST	1.30		
5	BIG CREEK-NO.3	RECTOR-NO.2	220.00	220.00	SP	20.07		
6	BIG CREEK-NO.3	RECTOR-NO.2	220.00	220.00	ST	54.32		
7	WALCREEK	WALNUT	220.00	220.00	SP	0.40		1
8	MESA	VINCENT-NO.1	220.00	220.00	ST	36.10		
9	MESA	VINCENT-NO.1	220.00	220.00	WH	0.02		1
10	REDONDO	VINCENT	220.00	220.00	SP	0.05		1
11	REDONDO	VINCENT	220.00	220.00	ST	9.59	3.76	1
12	REDONDO	VINCENT	220.00	220.00	ST	0.07	7.78	1
13	REDONDO	VINCENT	220.00	220.00	ST		0.25	1
14	REDONDO	VINCENT	220.00	220.00	WP	0.02	0.84	1
15	PADUA	RANCHO VISTA-NO.1&2	220.00	220.00	SP	1.33		
16	PADUA	RANCHO VISTA-NO.1&2	220.00	220.00	ST	13.88		
17	PADUA	RANCHO VISTA-NO.1&2	220.00	220.00	ST	13.88		2
18	LAGUNA BELL	VELASCO	220.00	220.00	ST	2.49		1
19	EAGLE ROCK	GOULD	220.00	220.00	SP	1.65		
20	EAGLE ROCK	GOULD	220.00	220.00	ST	21.87		1
21	REDONDO	VINCENT	220.00	220.00	SP	0.05		1
22	REDONDO	VINCENT	220.00	220.00	ST	9.59	3.76	1
23	REDONDO	VINCENT	220.00	220.00	ST	0.07	7.78	1
24	REDONDO	VINCENT	220.00	220.00	ST		0.25	1
25	REDONDO	VINCENT	220.00	220.00	WP	0.02	0.84	1
26	DESERT SUNLIGHT	RED BLUFF	220.00	220.00	SP	0.16		1
27	DEVERS	SENTINEL	220.00	220.00	SP	0.07		
28	DEVERS	SENTINEL	220.00	220.00	ST	0.34		1
29	EL CASCO	SAN BERNARDINO	220.00	220.00	ST	2.86		
30	EL CASCO	SAN BERNARDINO	220.00	220.00	ST	0.53		
31	EL CASCO	SAN BERNARDINO	220.00	220.00	ST	10.49		
32	DEVERS	MIRAGE-NO.1&2	220.00	220.00	ST	30.26		
33	EL CASCO	SAN BERNARDINO	220.00	220.00	ST	20.78		
34	DEVERS	SAN BERNARDINO	220.00	220.00	ST	43.20		
35	DEVERS	SAN BERNARDINO	220.00	220.00	ST	3.12		
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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	220 KV LINES CONT'D							
2	DEVERS	SAN BERNARDINO	220.00	220.00	ST	0.24		
3	EL CASCO	SAN BERNARDINO	220.00	220.00	WP	7.46		
4	EL CASCO	SAN BERNARDINO	220.00	220.00	WP	1.63		4
5	COACHELLA VALLEY	MIRAGE	220.00	220.00	ST	0.82		1
6	COACHELLA VALLEY	MIRAGE	220.00	220.00	ST	0.27		1
7	ETIWANDA	RANCHO VISTA-NO.1&2	220.00	220.00	ST	0.91		
8	MIRA LOMA	RANCHO VISTA-NO.1 & 2	220.00	220.00	SP	0.09		
9	MIRA LOMA	RANCHO VISTA-NO.1 & 2	220.00	220.00	ST	13.83		4
10	MOUNTAINVIEW	SAN BERNARDINO-NO.3&4	220.00	220.00	SP	0.55		2
11	ANTELOPE	BIG SKY	220.00	220.00	ST	0.20		
12	ALBA	SANDLOT	220.00	220.00	ST	0.06		
13	ELDORADO	MERCHANT NO.1	220.00	220.00	ST	0.29		
14	ELDORADO	MERCHANT NO.2	220.00	220.00	ST	0.30		
15	CPC EAST	WINDHUB	220.00	220.00	SP	0.21		
16	CPC WEST	WINDHUB	220.00	220.00	SP	0.22		
17	RISING TREE	WINDHUB	220.00	220.00	SP	0.04		
18	OCASO	SANDLOT	220.00	220.00	SP	0.05		
19	VINCENT	WINDSTAR NO.1	220.00	220.00	SP	0.74		
20	DESERT STAR	WHIRLWIND	220.00	220.00	ST	0.60		
21	KRAMER	LSP	220.00	220.00	ST	0.24		
22	RISING TREE	WINDHUB	220.00	220.00	ST	0.11		
23	SUNCREEK	WINDHUB	220.00	220.00	ST	0.37		
24	TEDDY	WHIRLWIND	220.00	220.00	ST	0.54		
25	VINCENT	WINDSTAR NO.1	220.00	220.00	ST	0.58		16
26	HIGHWIND	WINDHUB	220.00	220.00	SP	9.35		
27	HIGHWIND	WINDHUB	220.00	220.00	ST	0.19		1
28	KRAMER	VICTOR NO.2	220.00	220.00	ST	37.24		
29	COOL WATER	KRAMER	220.00	220.00	ST	44.37		
30	KRAMER	SANDLOT	220.00	220.00	ST	14.29		
31	KRAMER	VICTOR NO.1	220.00	220.00	SP	1.02		
32	BLM WEST	KRAMER	220.00	220.00	ST	49.50		
33	KRAMER	VICTOR NO.1	220.00	220.00	ST	36.22		
34	KRAMER	VICTOR	220.00	220.00	ST	35.66	47.20	1
35	BLM WEST	KRAMER	220.00	220.00	ST	27.00		
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

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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	220 KV LINES CONT'D							
2	COOL WATER	SANDLOT	220.00	220.00	ST	30.07		10
3	LUGO	VICTOR	220.00	220.00	ST	10.57	36.93	1
4	ELDORADO	PRIMM	220.00	220.00	SP	24.92		
5	ELDORADO	PRIMM	220.00	220.00	WH	0.05		1
6	AQUA	VINCENT	220.00	220.00	HF	11.95		1
7	AQUA	VINCENT	220.00	220.00	ST	0.53		1
8	AQUA	VINCENT	220.00	220.00	WP	0.66		1
9	PRIMM	SILVER STATE	220.00	220.00	SP	0.04		1
10	SAN ONOFRE	ENCINA	220.00	220.00	ST	20.00		
11	SAN ONOFRE	MISSION	220.00	220.00	ST	20.00		
12	SAN ONOFRE	VARIOUS	220.00	220.00	ST	20.00		
13	SAN ONOFRE	TALEGA NO.1	220.00	220.00	ST	20.00		
14	SAN ONOFRE	TALEGA NO.2	220.00	220.00	ST	20.00		
15	SAN ONOFRE	VIEJO	220.00	220.00	SP	23.22		9
16	BARRE	ELLIS NO.4	220.00	220.00	ST	12.67		
17	BARRE	ELLIS NO.1	220.00	220.00	SP	0.35		
18	BARRE	ELLIS NO.2	220.00	220.00	SP	0.04		
19	BARRE	ELLIS NO.3	220.00	220.00	SP	0.15		
20	BARRE	ELLIS NO.1	220.00	220.00	ST	37.79		
21	BARRE	ELLIS NO.2	220.00	220.00	ST	12.68		
22	BARRE	ELLIS NO.3	220.00	220.00	ST	12.53		4
23	BARRE	DEL AMO	220.00	220.00	ST	9.78		1
24	IVANPAH	PRIMM	220.00	220.00	ST	9.64		1
25	CHINO	VIEJO	220.00	220.00	SP	0.11		
26	CHINO	VIEJO	220.00	220.00	ST	34.98		1
27	KRAMER	VARIOUS	115.00	220.00	SP	0.07		
28	KRAMER	VARIOUS	115.00	220.00	ST	0.02		
29	KRAMER	VARIOUS	115.00	220.00	ST	0.09		
30	KRAMER	VARIOUS	115.00	220.00	WH	0.12		
31	KRAMER	VARIOUS	115.00	220.00	WH	0.05		4
32	CHINO	SOQUEL	66.00	220.00	SP	0.37	0.76	
33	CHINO	SOQUEL	66.00	220.00	ST	1.88		
34	CHINO	SOQUEL	66.00	220.00	WP	0.17	0.06	1
35	MIRA LOMA	VARIOUS	66.00	220.00	SP	0.10		10
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

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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	161 KV LINES							
2			161.00	161.00	SP	2.07	0.10	
3			161.00	161.00	WH	50.49		
4			161.00	161.00	WP	0.24		1
5								
6	115 KV LINES							
7			115.00	115.00	ST	3.44		
8			115.00	115.00	ST	3.50	0.58	
9			115.00	115.00	ST	0.06	0.06	
10			115.00	115.00	ST	19.08	4.95	
11			115.00	115.00	ST	371.14	133.52	
12			115.00	115.00	ST	7.51	9.62	
13			115.00	115.00	ST	2.66	2.84	
14			115.00	115.00	ST	6.71	3.59	
15			115.00	115.00	ST	1.34	0.27	
16			115.00	115.00	ST	1.37	1.14	
17			115.00	115.00	SP	0.48		
18			115.00	115.00	SP	0.06		
19			115.00	115.00	SP	0.21	0.03	
20			115.00	115.00	SP	0.61		
21			115.00	115.00	SP	5.41	0.66	
22			115.00	115.00	SP	5.32	1.55	
23			115.00	115.00	SP	6.23	2.33	
24			115.00	115.00	SP	4.36	0.35	
25			115.00	115.00	SP	2.04		
26			115.00	115.00	SP	0.35	0.32	
27			115.00	115.00	SP	52.76	18.34	
28			115.00	115.00	SP	4.13	0.23	
29			115.00	115.00	SP	79.72	66.19	
30			115.00	115.00	WH	2.00		
31			115.00	115.00	WH	0.13		
32			115.00	115.00	WH	0.81		
33			115.00	115.00	WH	1.55		
34			115.00	115.00	WH	37.37		
35			115.00	115.00	WH	60.91		
36					TOTAL	12,178.52	2,595.25	1,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	115 KV LINES CONT'D							
2			115.00	115.00	WH	143.55	6.79	
3			115.00	115.00	WH	26.52	0.18	
4			115.00	115.00	WH	0.74	0.24	
5			115.00	115.00	WH	26.85	2.43	
6			115.00	115.00	WH	83.60		
7			115.00	115.00	WH	3.05	0.79	
8			115.00	115.00	WP	0.02	0.20	
9			115.00	115.00	WP	0.15		
10			115.00	115.00	WP	6.40	0.32	
11			115.00	115.00	WP	25.32		
12			115.00	115.00	WP	73.83		
13			115.00	115.00	WP	31.70		
14			115.00	115.00	WP	61.68	0.89	
15			115.00	115.00	WP	7.41	0.26	
16			115.00	115.00	WP	32.76		
17			115.00	115.00	WP	2.02		
18			115.00	115.00	WP	353.85	34.03	
19			115.00	115.00	WP	5.06	0.13	
20			115.00	115.00	WP	8.02	5.88	
21			115.00	115.00	UG	8.64	5.25	135
22								
23	66 KV LINES							
24			66.00	66.00	ST	1.24		
25			66.00	66.00	ST	0.02		
26			66.00	66.00	ST	0.02		
27			66.00	66.00	SP	0.15		
28			66.00	66.00	SP	0.01		
29			66.00	66.00	WH	0.01		
30			66.00	66.00	WP	0.04		
31			66.00	66.00	WP	0.16		
32			66.00	66.00	WP	0.24		
33			66.00	66.00	ST	2.50		
34			66.00	66.00	ST	2.25	0.02	
35			66.00	66.00	ST	0.37		
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	66 KV LINES CONT'D							
2			66.00	66.00	SP	0.02		
3			66.00	66.00	SP	0.11		
4			66.00	66.00	SP	0.01		
5			66.00	66.00	SP	0.21	0.18	
6			66.00	66.00	WH	0.37		
7			66.00	66.00	WP	0.09		
8			66.00	66.00	WP	0.16		
9			66.00	66.00	WP	0.25		
10			66.00	66.00	WP	2.63	0.09	
11			66.00	66.00	WP	2.13		
12			66.00	66.00	ST	0.41	1.24	
13			66.00	66.00	ST	3.84		
14			66.00	66.00	ST	66.83	9.93	
15			66.00	66.00	ST	0.07	0.60	
16			66.00	66.00	ST	0.97		
17			66.00	66.00	ST	0.10		
18			66.00	66.00	ST	102.08	66.56	
19			66.00	66.00	ST	14.28	9.62	
20			66.00	66.00	ST	215.82	163.38	
21			66.00	66.00	ST	2.49	1.53	
22			66.00	66.00	ST	123.39	89.02	
23			66.00	66.00	ST		1.76	
24			66.00	66.00	ST	65.01	49.49	
25			66.00	66.00	ST	0.03		
26			66.00	66.00	ST	1.08		
27			66.00	66.00	SP	0.02		
28			66.00	66.00	SP	1.95	1.11	
29			66.00	66.00	SP	17.23	1.43	
30			66.00	66.00	SP	0.91	0.19	
31			66.00	66.00	SP	22.84		
32			66.00	66.00	SP	27.23	2.07	
33			66.00	66.00	SP	4.73	1.10	
34			66.00	66.00	SP	0.21		
35			66.00	66.00	SP	0.19	0.02	
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	66 KV LINES CONT'D							
2			66.00	66.00	SP	0.55	0.08	
3			66.00	66.00	SP	26.53	16.71	
4			66.00	66.00	SP	1.71		
5			66.00	66.00	SP	83.33	34.66	
6			66.00	66.00	SP	0.29		
7			66.00	66.00	SP	264.85	126.90	
8			66.00	66.00	SP	2.30		
9			66.00	66.00	SP	0.15	0.11	
10			66.00	66.00	SP	0.23	0.13	
11			66.00	66.00	WH		0.06	
12			66.00	66.00	WH	3.14	0.25	
13			66.00	66.00	WH	0.04	0.04	
14			66.00	66.00	WH	14.88		
15			66.00	66.00	WH	0.09		
16			66.00	66.00	WH	0.92		
17			66.00	66.00	WH	15.71	0.77	
18			66.00	66.00	WH	8.70	1.02	
19			66.00	66.00	WH	0.40		
20			66.00	66.00	WH	14.17	5.85	
21			66.00	66.00	WH	0.34		
22			66.00	66.00	WH	16.80	12.24	
23			66.00	66.00	WH	24.28	8.61	
24			66.00	66.00	WH	0.15		
25			66.00	66.00	WA	0.18		
26			66.00	66.00	WP	21.13		
27			66.00	66.00	WP	2.26	1.61	
28			66.00	66.00	WP	0.02		
29			66.00	66.00	WP		0.04	
30			66.00	66.00	WP	218.07	12.15	
31			66.00	66.00	WP	20.62	2.69	
32			66.00	66.00	WP	21.33	12.55	
33			66.00	66.00	WP	0.57		
34			66.00	66.00	WP	233.79	45.04	
35			66.00	66.00	WP	91.68	9.70	
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	66 KV LINES CONT'D							
2			66.00	66.00	WP	4.87	1.02	
3			66.00	66.00	WP	6.10	0.97	
4			66.00	66.00	WP	49.36	2.85	
5			66.00	66.00	WP	308.32	71.79	
6			66.00	66.00	WP	0.02		
7			66.00	66.00	WP	34.37	1.44	
8			66.00	66.00	WP	736.63	136.33	
9			66.00	66.00	WP	755.10	252.09	
10			66.00	66.00	WP	0.03		
11			66.00	66.00	WP	0.10		
12			66.00	66.00	WP	2.55		
13			66.00	66.00	UG	1.88		
14			66.00	66.00	UG	0.39	0.19	
15			66.00	66.00	UG	2.44		
16			66.00	66.00	UG	8.04	0.19	
17			66.00	66.00	UG	0.06		
18			66.00	66.00	UG	152.18	51.21	
19			66.00	66.00	UG	8.98	8.83	
20			66.00	66.00	UG	5.45	1.29	
21			66.00	66.00	UG	4.86		
22			66.00	66.00	UG	4.45	0.07	
23			66.00	66.00	UG	0.20		
24			66.00	66.00	UG	3.27	93.66	832
25								
26	55 KV LINES							
27			55.00	55.00	SP	0.30		
28			55.00	55.00	SP	0.08		
29			55.00	55.00	SP	0.41	0.04	
30			55.00	55.00	SP	0.06		
31			55.00	55.00	WH	0.79		
32			55.00	55.00	WH	0.92		
33			55.00	55.00	WH	0.77		
34			55.00	55.00	WH	0.03		
35			55.00	55.00	WH	0.26		
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	55 KV LINES CONT'D							
2			55.00	55.00	WP	2.99		
3			55.00	55.00	WP	6.68		
4			55.00	55.00	WP	50.35	0.26	
5			55.00	55.00	WP	7.77	0.64	
6			55.00	55.00	WP	16.30		
7			55.00	55.00	WP	2.36		
8			55.00	55.00	WP	6.60		7
9								
10	33 KV LINES							
11			33.00	33.00	ST	8.32		
12			33.00	33.00	ST	0.05		
13			33.00	33.00	ST	0.02		
14			33.00	33.00	ST	0.08		
15			33.00	33.00	SP	0.74		
16			33.00	33.00	SP	0.15	0.48	
17			33.00	33.00	SP	4.42		
18			33.00	33.00	SP	0.08	0.04	
19			33.00	33.00	SP	0.15	0.24	
20			33.00	33.00	SP		0.02	
21			33.00	33.00	WH	0.33		
22			33.00	33.00	WH		0.26	
23			33.00	33.00	WP	2.55	0.72	
24			33.00	33.00	WP	4.53		
25			33.00	33.00	WP	0.12		
26			33.00	33.00	WP	5.83	2.43	
27			33.00	33.00	WP	0.34		
28			33.00	33.00	WP	4.12	9.94	
29			33.00	33.00	WP	0.30	0.09	
30			33.00	33.00	UG	0.32	0.10	
31			33.00	33.00	UG	1.19	0.18	10
32								
33								
34								
35								
36					TOTAL	12,178.52	2,595.25	1,268

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	04/14/2021	End of 2020/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.
								1
1272 KCM ACSR	136,841	95,501,597	95,638,438					2
2312 KCM ACSR								3
1250 KCM XLP								4
300 KCM XLP GRD								5
2312 KCM ACSR	668,871	16,296,756	16,965,627					6
								7
								8
2156 KCM ACSR	3,721,749	56,833,911	60,555,660					9
2156 KCM ACSR	1,751,358	21,417,485	23,168,843					10
1033.5 KCM ACSR	4,029,224	13,768,075	17,797,299					11
2156 KCM ACSR								12
2156 KCM ACSR	10,676,853	58,708,106	69,384,959					13
2156 KCM ACSR	1,340,955	47,491,866	48,832,821					14
2156 KCM ACSR	28,674,338	274,441,066	303,115,404					15
2156 KCM ACSR	2,494,448	34,473,919	36,968,367		68,746	13,983	82,728	16
2156 KCM ACSR	177,040	2,428,944	2,605,984					17
2156 KCM ACSR	1,448,120	30,644,677	32,092,797	20,580	128,270	30,276	179,127	18
2156 KCM ACSR	36,677	8,172,492	8,209,169		695	141	836	19
2156 KCM ACSR	5,495,635	41,313,394	46,809,029	9,037		1,838	10,876	20
2156 KCM ACSR	607,445	36,690,916	37,298,361					21
2156 KCM ACSR	132,115	13,665,020	13,797,135					22
2156 KCM ACSR	151,231	10,461,043	10,612,274					23
2156 KCM ACSR	748,544	3,508,598	4,257,142					24
2156 KCM ACSR	6,013,388	30,127,863	36,141,251					25
2156 KCM ACSR	15,244,178	436,918,489	452,162,667					26
2156 ACSR	76,966,727	848,803,098	925,769,825		1,070,042	217,646	1,287,688	27
2156 ACSR								28
5000 KCM CU								29
2156 ACSR		2,734,590	2,734,590	33,583	431,492	94,596	559,672	30
1927 ACCR								31
2156 Bundle ACSR		7,296	7,296	18,745	20,542	7,991	47,278	32
2156 ACSR								33
1033.5 KCM ACSR	2,690,512	77,759,354	80,449,866					34
1033.5 KCM ACSR	3,577,064	44,247,177	47,824,241					35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1033.5 KCM ACSR								2
3000 KCM HPOF								3
1033.5 KCM ACSR								4
1590 KCM ACSR								5
1590 KCM ACSR								6
1590 KCM ACSR								7
605 KCM ACSR								8
605 KCM ACSR								9
650 KCM CAL								10
954 KCM SAC								11
1033.5 KCM ACSR	11,017	1,332,368	1,343,385					12
1033.5 KCM ACSR								13
2156 KCM ACSR	1,681,104	387,369,461	389,050,565					14
								15
								16
605 KCM ACSR		235,526	235,526	1,071	189,022	38,665	228,758	17
606 KCM ACSR								18
607 KCM ACSR								19
605 KCM ACSR	42,222	1,312,512	1,354,734	6,448		1,311	7,759	20
1033 ACSR		1,135,466	1,135,466	3,854,261	991,007	985,527	5,830,795	21
1590 KCM ACSR		18,104	18,104	3,234		658	3,892	22
1033.5 KCM ACSR		15,841	15,841	49		10	58	23
605 KCM ACSR	4,931,556	46,854,613	51,786,169		555,041	112,895	667,936	24
1033.5 KCM ACSR								25
605 KCM ACSR								26
1033.5 KCM ACSR		85,040	85,040	1,957	810,269	165,207	977,433	27
650 KCM CAL								28
1590 KCM ACSR		302,490	302,490	26,231	738,579	155,562	920,372	29
1033.5 KCM ACSR		82,383	82,383	5,815	65,408	14,487	85,710	30
605 KCM ACSR								31
1033.5 KCM ACSR		632,889	632,889	7,883	193,727	41,007	242,617	32
1033.5 KCM ACSR		101,391	101,391		13,265	2,698	15,963	33
2156 ACSR		185,665	185,665	25,212	48,266	14,945	88,423	34
2156 ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	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	04/14/2021	End of 2020/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.
								1
1590 KCM ACSR								2
1590 KCM ACSR								3
1033 ACSR		238,667	238,667	29,282	155,255	37,535	222,071	4
666.6 ACSS								5
1590 KCM ACSR		12,452	12,452	19,011	44,439	12,906	76,355	6
605 KCM ACSR		16,624	16,624		227	46	273	7
1590 KCM ACSR	26	644,801	644,827	55,581	96,897	31,014	183,493	8
1590 KCM ACSR								9
1590 KCM ACSR								10
2156 ACSR	7,876,192	133,171,835	141,048,027	4,235		861	5,097	11
1590 KCM ACSR								12
2156 ACSR								13
1590 ACSR								14
1590 KCM ACSR		1,444,838	1,444,838	2,658	32,612	7,174	42,444	15
1033.5 KCM ACSR		7,378	7,378	7,633	13,420	4,282	25,336	16
1033.5 KCM ACSR								17
1033 ACSR								18
636 ACSS								19
1033 ACSR								20
1033.5 KCM ACSR		806,842	806,842	10,164	1,261	2,324	13,749	21
1033.5 KCM ACSR	1,198,519	12,147,975	13,346,494					22
1033 KCM SAC								23
1033.5 KCM ACSR								24
1033 KCM SAC								25
1033.5 KCM ACSR								26
1590 KCM ACSR	78,248	2,955,875	3,034,123	7,979	5,042	2,648	15,669	27
2156 ACSR		6,441	6,441	17,761	-752	3,460	20,468	28
2156 ACSR								29
1033.5 KCM ACSR								30
1590 KCM ACSR	186,657	276,517	463,174					31
1590 KCM ACSR								32
1033.5 KCM ACSR	145,317	521,234	666,551					33
605 KCM ACSR								34
605 KCM ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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								1
1033.5 KCM ACSR								2
1033.5 KCM ACSR								3
605 KCM ACSR								4
605 KCM ACSR								5
605 KCM ACSR								6
1033.5 KCM ACSR	33,954	1,169,080	1,203,034					7
2156 KCM ACSR								8
1033.5 KCM ACSR	72,932	1,968,581	2,041,513					9
2156 KCM ACSR								10
1033.5 KCM ACSR								11
1033 KCM SAC								12
1033.5 KCM ACSR								13
1590 KCM ACSR								14
1590 KCM ACSR								15
605 KCM ACSR								16
605 KCM ACSR								17
666.6 KCM ACSR								18
1033.5 KCM ACSR	3,948,771	58,755,958	62,704,729					19
3000 KCM HPOF								20
605 KCM ACSR								21
1590 KCM ACSR								22
605 KCM ACSR								23
1033.5 KCM ACSR	92,843,104	206,246,192	299,089,296					24
1033.5 KCM ACSR								25
1590 KCM ACSR	9,806,314	35,606,400	45,412,714					26
1033.5 KCM ACSR								27
605 KCM ACSR	31,372	1,323,305	1,354,677					28
1033.5 KCM ACSR	1,505,890	4,562,079	6,067,969					29
1033.5 KCM ACSR	3,514,705	45,812,922	49,327,627					30
1033.5 KCM ACSR								31
1590 KCM ACSR								32
1033.5 KCM ACSR	1,634,441	7,342,280	8,976,721					33
650 KCM CAL								34
1033.5 KCM ACSR	3,608,110	25,834,957	29,443,067					35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

TRANSMISSION LINE STATISTICS (Continued)

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								1
1033.5 KCM ACSR								2
3000 KCM HPOF								3
1590 KCM ACSR								4
1590 KCM ACSR								5
336 KCM ACSR ()								6
1033.5 KCM ACSR	1,155,551	9,084,237	10,239,788					7
605 KCM ACSR								8
605 KCM ACSR								9
1033.5 KCM ACSR	5,791,623	36,537,910	42,329,533					10
1033.5 KCM ACSR								11
1590 KCM ACSR								12
1590 KCM ACSR								13
605 KCM ACSR								14
1033.5 KCM ACSR	4,304,652	17,000,735	21,305,387					15
1033.5 KCM ACSR								16
1590 KCM ACSR								17
605 KCM ACSR	532,778	30,360,650	30,893,428					18
1033.5 KCM ACSR	15,107,982	56,474,912	71,582,894					19
1590 KCM ACSR								20
1033.5 KCM ACSR	25,048	1,197,458	1,222,506					21
1590 KCM ACSR	2,324,974	23,024,795	25,349,769					22
1033.5 KCM ACSR								23
605 KCM ACSR	332,719	1,655,926	1,988,645					24
605 KCM ACSR								25
1590 KCM ACSR	12,056,709	11,710,845	23,767,554					26
1590 KCM ACSR								27
605 KCM ACSR	9,034	300,481	309,515					28
666.6 KCM ACSR								29
605 KCM ACSR	14,507,992	135,148,419	149,656,411					30
605 KCM ACSR								31
666.6 KCM ACSR								32
605 KCM ACSR		6,678,804	6,678,804					33
605 KCM ACSR								34
2156 ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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								1
2156 ACSR				23,805	69,810	19,041	112,657	2
2156 ACSR								3
2156 ACSR								4
1590 KCM ACSR								5
1590 KCM ACSR								6
2156 ACSR	16,796,780	64,886,849	81,683,629	4,028	2,607	1,350	7,985	7
2156 ACSR	18,144,560	80,781,271	98,925,831	7,936		1,614	9,550	8
2156 KCM ACSR	71,262	76,831,765	76,903,027	3,814		776	4,590	9
2156 ACSR	11,885,452	224,893,142	236,778,594	10,012	409	2,120	12,541	10
2156 ACSR		237,004	237,004	7,588		1,543	9,131	11
1033 ACSR	18,165,988	383,802,802	401,968,790	326,719	241,409	115,557	683,685	12
2156 KCMIL ACSR		51,478	51,478	5,605		1,140	6,746	13
2156 KCM ACSR				25,380	15,634	8,342	49,357	14
2156 KCM ACSR								15
1033.5 KCM ACSR								16
1033 KCM SAC								17
1033.5 KCM ACSR								18
1033.5 KCM ACSR								19
1033 KCM SAC								20
1033.5 KCM ACSR								21
1033.5 KCM ACSR								22
2156 ACSR				1,504		306	1,810	23
2156 ACSR								24
2156 ACSR								25
1033.5 KCM ACSR	7,585	1,714,299	1,721,884	516	226,582	46,192	273,290	26
1590 ACSR		101,194	101,194					27
1590 ACSR								28
1590 ACSR								29
1033.5 KCM ACSR				10,198	33,040	8,795	52,033	30
1590 ACSR		50,492,641	50,492,641	16,081	8,387	4,977	29,446	31
1590 KCM ACSR		103,351	103,351	38,091	8,435	9,463	55,989	32
1033 ACSR		31,685	31,685					33
1033 ACSR								34
1590 ACSR		1,430	1,430	322	4,227	925	5,475	35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
1033.5 ACSR								2
605 ACSR								3
666.6 ACSR								4
1033.5 ACSR								5
1033.5 ACSR								6
1590 KCM ACSR								7
1033 ACSR		4,626,410	4,626,410	3,785	219,147	45,344	268,276	8
1590 ACSR								9
1590 ACSR								10
1033 ACSR								11
1590 ACSR								12
2156 ACSR								13
1590 ACSR								14
1590 KCM ACSR		34,265,180	34,265,180	3,498	478,694	98,078	580,270	15
1033.5 ACSR								16
1033.5 KCM ACSR								17
1033 ACSR		406,064	406,064	19,231	3,014	4,525	26,771	18
NO_DATA								19
NO_DATA								20
1590 ACSR								21
1033 ACSR								22
1590 ACSR								23
2156 ACSR								24
1590 ACSR								25
1033 ACSR				3,606		734	4,340	26
1590 ACSR								27
1590 ACSR								28
1033 ACSR		82,149	82,149	53,218	52,281	21,458	126,957	29
1590 ACSR								30
2741 ACCC								31
636 ACSS								32
1033 ACSR								33
1033 ACSR								34
1590 ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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								1
605 ACSR								2
1033 ACSR								3
1590 ACSR								4
1334.6 ACSS		492,540	492,540	426		87	513	5
1033 ACSR								6
2156 ACSR		739,562	739,562	29,224	8,289	7,630	45,143	7
1590 ACSR								8
1334.6 ACSS								9
1590 KCM ACSR				971		198	1,169	10
1590 ACSR								11
1590 KCM ACSR								12
954 ACSR								13
954 ACSR								14
1590 ACSR								15
1590 ACSR								16
1590 KCM ACSR								17
1590 KCM ACSR								18
1590 KCM ACSR								19
1590 ACSR								20
1590 ACSR								21
1590 KCM ACSR								22
1590 KCM ACSR								23
1590 KCM ACSR								24
1590 KCM ACSR								25
1590 ACSR	3,268,655	60,391,262	63,659,917	1,940		395	2,335	26
1590 ACSR								27
1033 ACSR		132,552	132,552	38,067	5,663	8,895	52,624	28
1590 ACSR								29
1590 ACSR								30
1033 ACSR								31
1033 ACSR								32
1033 ACSR								33
1033 ACSR								34
1590 ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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								1
1590 ACSR								2
1033 ACSR								3
1590 ACSR	2,530,844	214,455,556	216,986,400	3,921		798	4,719	4
1590 ACSR								5
605 ACSR				1,190	2,176	685	4,051	6
605 ACSR								7
605 ACSR								8
1590 KCM ACSR		18	18	370		75	445	9
NO_DATA		560,821	560,821	57,658	211,071	54,659	323,389	10
NO_DATA								11
NO_DATA								12
NO_DATA								13
NO_DATA								14
1590 KCM ACSR								15
1033 ACSR		799,678	799,678	55,141	15,438	14,356	84,935	16
1033 ACSR								17
1033 ACSR								18
1033 ACSR								19
1033 ACSR								20
1033 ACSR								21
1033 ACSR								22
1590 ACSR								23
1590 ACSR								24
1590 ACSR								25
1590 ACSR								26
954 KCM SAC								27
4/0 ACSR								28
954 KCM SAC								29
1033.5 KCM ACSR								30
4/0 ACSR								31
954 KCM SAC								32
954 KCM SAC								33
954 KCM SAC								34
605 KCM ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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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) 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
336 KCM ACSR				340,927	75,700	84,742	501,368	2
336 KCM ACSR								3
336 KCM ACSR								4
								5
								6
115 KCM STRAND	220,642	25,041,456	25,262,098	10,218,585	2,268,938	2,539,961	15,027,484	7
2/0 STRANDED CU								8
336 KCM ACSR								9
336.4 KCM ACSR								10
4/0 ACSR								11
4/0 STRANDED CU								12
636 KCM SAC								13
653.9 KCM ACSR								14
795 KCM SAC								15
954 KCM SAC								16
1033 KCM SAC								17
1033.5 KCM ACSR								18
2/0 STRANDED CU								19
266.8 KCM ACSR								20
336 KCM ACSR								21
336.4 KCM ACSR								22
4/0 ACSR								23
4/0 STRANDED CU								24
477 MCM AL								25
636 KCM SAC								26
653.9 KCM ACSR								27
795 KCM SAC								28
954 KCM SAC								29
1033 KCM SAC								30
1033.5 KCM ACSR								31
2/0 STRANDED CU								32
266.8 KCM ACSR								33
336 KCM ACSR								34
336.4 KCM ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	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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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
4/0 ACSR								2
4/0 STRANDED CU								3
636 KCM SAC								4
653.9 KCM ACSR								5
795 KCM SAC								6
954 KCM SAC								7
1033.5 KCM ACSR								8
115 KCM STRAND								9
2/0 STRANDED CU								10
266.8 KCM ACSR								11
336 KCM ACSR								12
336.4 KCM ACSR								13
4/0 ACSR								14
4/0 STRANDED CU								15
477 MCM AL								16
636 KCM SAC								17
653.9 KCM ACSR								18
795 KCM SAC								19
954 KCM SAC								20
1750 KCM XLP								21
								22
								23
115 KCM STRAND	53,838,910	2,099,025,612	2,152,864,522	24,948,387	5,539,548	6,201,242	36,689,177	24
336 KCM ACSR								25
4/0 ACSR								26
115 KCM STRAND								27
4/0 ACSR								28
4/0 ACSR								29
115 KCM STRAND								30
336 KCM ACSR								31
4/0 ACSR								32
2/0 STRANDED CU								33
4/0 STRANDED CU								34
954 KCM SAC								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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								1
1033.5 KCM ACSR								2
2/0 STRANDED CU								3
4/0 STRANDED CU								4
954 KCM SAC								5
4/0 STRANDED CU								6
2/0 STRANDED CU								7
336 KCM ACSR								8
336.4 KCM ACSR								9
4/0 STRANDED CU								10
954 KCM SAC								11
1033.5 KCM ACSR								12
1590 KCM ACSR								13
2/0 STRANDED CU								14
250 KCM								15
3/0 SOLID CU								16
300 KCM								17
336 KCM ACSR								18
336.4 KCM ACSR								19
4/0 STRANDED CU								20
605 KCM ACSR								21
653.9 KCM ACSR								22
666.6 KCM ACSR								23
954 KCM SAC								24
NO. 2 SAC								25
NO. 2 STRANDED								26
1/0 ACSR								27
1033.5 KCM ACSR								28
2/0 STRANDED CU								29
250 KCM								30
3/0 SOLID CU								31
336 KCM ACSR								32
336.4 KCM ACSR								33
336.4 KCM SAC								34
4/0 ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
4/0 SAC								2
4/0 STRANDED CU								3
605 KCM ACSR								4
653.9 KCM ACSR								5
954 KCM ACSR								6
954 KCM SAC								7
NO 2 SOLID CU								8
NO. 2 SAC								9
NO. 2 STRANDED								10
1033.5 KCM ACSR								11
2/0 STRANDED CU								12
250 KCM								13
3/0 SOLID CU								14
3/0 STRANDED CU								15
300 KCM								16
336 KCM ACSR								17
336.4 KCM ACSR								18
4/0 SAC								19
4/0 STRANDED CU								20
605 KCM ACSR								21
653.9 KCM ACSR								22
954 KCM SAC								23
NO. 2 SAC								24
3/0 SOLID CU								25
1/0 ACSR								26
1033.5 KCM ACSR								27
1590 KCM ACSR								28
1750 KCM XLP								29
2/0 STRANDED CU								30
250 KCM								31
3/0 SOLID CU								32
300 KCM								33
336 KCM ACSR								34
336.4 KCM ACSR								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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								1
336.4 KCM SAC								2
4/0 ACSR								3
4/0 SAC								4
4/0 STRANDED CU								5
400 KCM LPOF CU								6
605 KCM ACSR								7
653.9 KCM ACSR								8
954 KCM SAC								9
NO 2 SOLID CU								10
NO. 2 SAC								11
NO. 2 STRANDED								12
1000 KCM HPOF								13
1250 KCM XLP								14
1500 KCM EPR								15
1500 KCM XLP								16
1590 KCM ACSR								17
1750 KCM XLP								18
2000 KCM HPOF								19
3000 KCM CU								20
500 KCM HPOF CU								21
750 KCM HPOF CU								22
954 KCM SAC								23
NO CABLE								24
								25
								26
2/0 STRANDED CU				624,268	138,613	155,170	918,051	27
336 KCM ACSR								28
4/0 ACSR								29
NO. 2 STRANDED								30
2/0 STRANDED CU								31
336 KCM ACSR								32
4/0 ACSR								33
NO. 2 ACSR								34
NO. 2 STRANDED								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								1
115 KCM STRAND								2
2/0 ACSR								3
2/0 STRANDED CU								4
336 KCM ACSR								5
4/0 ACSR								6
NO. 2 ACSR								7
NO. 2 STRANDED								8
								9
								10
2/0 STRANDED CU				217,236	48,235	53,997	319,467	11
336 KCM ACSR								12
4/0 STRANDED CU								13
653.9 KCM ACSR								14
2/0 STRANDED CU								15
336 KCM ACSR								16
336.4 KCM ACSR								17
4/0 SAC								18
653.9 KCM ACSR								19
954 KCM SAC								20
336 KCM ACSR								21
653.9 KCM ACSR								22
2/0 STRANDED CU								23
336 KCM ACSR								24
336.4 KCM ACSR								25
4/0 SAC								26
4/0 STRANDED CU								27
653.9 KCM ACSR								28
954 KCM SAC								29
1500 KCM XLP								30
750 KCM HPOF CU								31
								32
								33
								34
								35
	481,013,504	6,841,075,657	7,322,089,161	41,271,658	15,350,119	11,516,863	68,138,645	36

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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	VALLEY	TRITON	14.50	OH		1	1
3	GOODRICH	MESA	0.19	OH		1	1
4	LAGUNA BELL	MESA	0.44	OH		1	1
5	LAGUNA BELL	MESA	0.27	OH		1	1
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16	UNDERGROUND	CONSTRUCTION					
17	MESA	NEWMARK	3.15	UG		6	6
18	MESA	LAGUNA BELL-NARROWS	0.09	UG		2	2
19	MESA	NARROWS	5.15	UG		7	7
20	CHINO	FRANCIS-SAN ANTONIO	0.26	UG		3	3
21							
22							
23	Please see footnote:						
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		24.05			22	22

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
954	SAC	SC-LWS	115		10,480,745	53,402,940		63,883,685	2
1590	ASCR	DCT	220			526,665		526,665	3
1590	ASCR	DCT	220			284,946		284,946	4
1590	ASCR	DCT	220		608,546	107,127		715,673	5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
3000	CUG	DTP	66		502,995	15,499,353		16,002,348	17
3000	ODC	DTP	66		516,022	1,681,347		2,197,369	18
3000	CUG	DTP	66		807,148	23,354,493		24,161,641	19
3000	ODC	DTP	66		392,166	1,196,362		1,588,528	20
		DTS	66						21
		STP	66						22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					13,307,622	96,053,233		109,360,855	44

Schedule Page: 424 Line No.: 2 Column: e
N/A
Schedule Page: 424 Line No.: 3 Column: e
N/A
Schedule Page: 424 Line No.: 4 Column: e
N/A
Schedule Page: 424 Line No.: 5 Column: e
N/A
Schedule Page: 424 Line No.: 17 Column: e
N/A
Schedule Page: 424 Line No.: 18 Column: e
N/A
Schedule Page: 424 Line No.: 19 Column: e
N/A
Schedule Page: 424 Line No.: 20 Column: e
N/A
Schedule Page: 424 Line No.: 23 Column: a
UG Chino - Francis - San Antonio contains three different types of UG configuration and spacing.

The following lines below has been reported in service as of Year End 2020, but has not yet been updated as operational in the circuit map.

Overhead Lines:
Valley - Triton
Goodrich - Mesa
Laguna Bell - Mes
Laguna Bell - Mesa

Underground Lines:
Mesa - New Mark
Mesa - Laguna Bell-Narrows
Mesa - Narrows

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	66.00	12.00	
9	CHEVMAIN-EL SEGUNDO	TU	220.00	66.00	
10	CHEVMAIN-EL SEGUNDO	TU	66.00	16.00	
11	CHEVMAIN-EL SEGUNDO	TU	66.00	13.20	
12	CHINO-ONTARIO	TU	220.00	66.00	
13	CHINO-ONTARIO	TU	72.00	12.00	
14	CHINO-ONTARIO	TU	66.00	12.00	
15	CIMA-HI DESERT	TU	220.00	16.00	
16	COLORADO RIVER-BLYTHE	TU	500.00	220.00	13.80
17	COLORADO RIVER-BLYTHE	TU	66.00	12.00	
18	COLORADO RIVER-BLYTHE	TU	66.00	4.00	
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	500.00	17.00	
23	DEVERS-PALM SPRINGS	TA	220.00	115.00	
24	DEVERS-PALM SPRINGS	TA	115.00	12.00	
25	EAGLE MOUNTAIN-BLYTHE	TU	220.00	161.00	
26	EAGLE MOUNTAIN-BLYTHE	TU	220.00	66.00	72.00
27	EAGLE MOUNTAIN-BLYTHE	TU	220.00	66.00	12.00
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	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

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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	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	INYO-BISHOP	TU	220.00	115.00	
5	IVANPAH-NIPTON	TU	220.00	115.00	
6	JOHANNA-SANTA ANA	TU	220.00	66.00	
7	JOHANNA-SANTA ANA	TU	66.00	12.00	
8	KRAMER-RIDGECREST	TU	230.00	115.00	
9	KRAMER-RIDGECREST	TU	115.00	33.00	
10	KRAMER-RIDGECREST	TU	33.00	2.40	
11	LA CIENEGA-SANTA MONICA	TU	220.00	66.00	
12	LA FRESA-REDONDO	TU	220.00	66.00	
13	LA FRESA-REDONDO	TU	66.00	16.00	
14	LAGUNA BELL-MONTEBELLO	TU	220.00	66.00	
15	LAGUNA BELL-MONTEBELLO	TU	66.00	16.00	
16	LIGHTHIPE-LONG BEACH	TA	220.00	66.00	
17	LIGHTHIPE-LONG BEACH	TA	66.00	12.00	
18	LUGO-HI DESERT	TA	500.00	220.00	
19	MESA-MONTEBELLO	TA	220.00	66.00	
20	MESA-MONTEBELLO	TA	66.00	16.00	
21	MIRA LOMA-ONTARIO	TA	525.00	220.00	13.80
22	MIRA LOMA-ONTARIO	TA	230.00	70.50	
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	220.00	66.00	
35	RECTOR-VISALIA	TA	220.00	10.00	
36	RECTOR-VISALIA	TA	66.00	12.00	
37	RECTOR-VISALIA	TA	66.00	12.00	
38	RECTOR-VISALIA	TA	66.00	4.00	
39	RED BLUFF-VIDAL	TU	500.00	220.00	13.80
40	RIO HONDO-MONROVIA	TU	230.00	66.00	

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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	RIO HONDO-MONROVIA	TU	220.00	66.00	
2	RIO HONDO-MONROVIA	TU	66.00	16.00	
3	RIO HONDO-MONROVIA	TU	66.00	12.00	
4	SAN BERNARDINO-INLAND	TU	220.00	66.00	
5	SAN BERNARDINO-INLAND	TU	66.00	12.00	
6	SANTA CLARA-VENTURA	TU	220.00	72.00	
7	SANTA CLARA-VENTURA	TU	220.00	66.00	
8	SANTIAGO-EL TORO	TU	220.00	66.00	
9	SANTIAGO-EL TORO	TU	66.00	33.00	
10	SANTIAGO-EL TORO	TU	66.00	12.00	
11	SAUGUS-SAN FERNANDO	TU	220.00	66.00	
12	SAUGUS-SAN FERNANDO	TU	66.00	16.00	
13	SERRANO-ORANGE	TU	500.00	220.00	
14	SPRINGVILLE-PORTERVILLE	TU	220.00	66.00	
15	SPRINGVILLE-PORTERVILLE	TU	66.00	12.00	
16	VALLEY-SAN JACINTO	TA	525.00	120.00	
17	VALLEY-SAN JACINTO	TA	115.00	12.00	
18	VESTAL-DELANO	TU	220.00	66.00	
19	VESTAL-DELANO	TU	66.00	12.00	
20	VESTAL-DELANO	TU	66.00	12.00	
21	VICTOR-HI DESERT	TU	220.00	115.00	
22	VICTOR-HI DESERT	TU	115.00	33.00	
23	VICTOR-HI DESERT	TU	115.00	12.00	
24	VIEJO-LAKE FOREST	TU	220.00	66.00	
25	VIEJO-LAKE FOREST	TU	66.00	12.00	
26	VILLA PARK-SANTA ANA	TU	220.00	66.00	
27	VILLA PARK-SANTA ANA	TU	66.00	12.00	
28	VINCENT-LANCASTER	TA	500.00	220.00	
29	VISTA-INLAND	TA	220.00	115.00	
30	VISTA-INLAND	TA	220.00	66.00	
31	WALNUT-COVINA	TU	220.00	66.00	
32	WALNUT-COVINA	TU	66.00	12.00	
33	ALAMITOS-LONG BEACH	TU	220.00	66.00	
34	BIG CREEK 1-BIG CREEK	TU	230.00	13.10	
35	BIG CREEK 1-BIG CREEK	TU	33.90	7.40	
36	BIG CREEK 1-BIG CREEK	TU	33.00	14.40	
37	BIG CREEK 1-BIG CREEK	TU	13.40	7.20	
38	BIG CREEK 2-NR. BIG CREEK	TU	230.00	7.20	
39	BIG CREEK 2-NR. BIG CREEK	TU	220.00	13.80	
40	BIG CREEK 3-NR. AUBERRY	TU	240.00	13.80	

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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	BIG CREEK 3-NR. AUBERRY	TU	230.00	13.80	
2	BIG CREEK 4-NR. AUBERRY	TU	240.00	11.50	
3	BIG CREEK 4-NR. AUERRY	TU	12.00	2.40	
4	BIG CREEK 8-NR. BIG CREEK	TU	240.00	13.50	
5	BOREL-LAKE ISABELLA	TU	66.00	2.40	
6	BUCKWIND-NORTH PALM SPRINGS	TU	115.00	12.47	
7	CHEVGEN-EL SEGUNDO	TU	66.00	13.80	
8	COOL WATER-DAGGETT	TU	115.00	13.20	
9	COOL WATER-DAGGETT	TU	115.00	4.16	
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	HUNTINGTON BEACH-HUNTINGTON BEACH	TU	66.00	4.00	
18	KAWEAH 1-THREE RIVERS	TU	66.00	2.40	
19	KAWEAH 2-THREE RIVERS	TU	66.00	2.40	
20	KAWEAH 3-THREE RIVERS	TU	72.00	2.40	
21	KERN RIVER 1-KERN CANYON	TU	70.00	2.60	
22	KERN RIVER 3-KERNVILLE	TU	71.54	11.00	
23	LUNDY-NR. LEE VINING	TU	55.00	16.00	
24	LUNDY-NR. LEE VINING	TU	55.00	2.40	
25	MAMMOTH POOL-BIG CREEK	TU	230.00	13.20	
26	MCGRATH BEACH-OXNARD	TU	66.00	13.00	
27	MIDWIND-LANCASTER	TU	66.00	12.00	
28	ORMOND BEACH-OXNARD	TU	220.00	66.00	
29	PARKER-BLYTHE	TU	161.00	66.00	
30	PEBBLY BEACH-AVALON	TU	12.00	2.40	
31	POOLE-NR. LEE VINING	TU	12.00	7.00	
32	POOLE-NR. LEE VINING	TU	7.20	122.00	
33	PORTAL-BIG CREEK	TU	33.00	4.00	
34	RENWIND-PALM SPRINGS	TU	115.00	12.47	
35	RUSH CREEK-NR. JUNE LAKE	TU	115.00	2.40	
36	SANTA ANA RIVER 1-FOOTHILL	TU	34.40	2.40	
37	SANTA ANA RIVER 3-FOOTHILL	TU	34.50	4.16	
38	SOUTHWIND-LANCASTER	TU	66.00	12.00	
39	VENWIND-PALM SPRINGS	TU	115.00	12.00	
40	WHIRLWIND-ROSAMOND	TU	500.00	220.00	13.80

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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	WINDHUB-TEHACAHPI	TU	533.00	220.00	13.80
2	WINDHUB-TEHACAHPI	TU	230.00	66.00	
3	ACTON-SAN JACINTO	DU	66.00	12.00	
4	AEROJET-AZUSA	DU	66.00	12.00	
5	AIR PRODUCTS-CARSON	DU	66.00	16.00	
6	ALDER-FOOTHILL	DU	66.00	12.00	
7	ALESSANDRO-SAN JACINTO	DU	115.00	33.00	
8	ALESSANDRO-SAN JACINTO	DU	115.00	12.00	
9	ALHAMBRA-MONTEBELLO	DU	66.00	16.00	
10	ALHAMBRA-MONTEBELLO	DU	66.00	4.00	
11	ALLEN-MONROVIA	DU	16.00	4.00	
12	ALON-COMPTON	DU	66.00	12.00	
13	AMADOR-EL MONTE	DU	66.00	16.00	
14	AMADOR-EL MONTE	DU	66.00	4.00	
15	AMALIA-MONTEBELLO	DU	16.00	4.00	
16	AMARGO-RIDGECREST	DU	33.00	4.00	
17	AMBOY-TWENTY-NINE PALMS	DU	33.00	12.00	
18	AMCO-TORRANCE	DU	66.00	12.00	
19	AMCO-TORRANCE	DU	12.00	4.00	
20	AMERON-ETIWANDA	DU	66.00	33.00	
21	ANAVERDE-LANCASTER	DU	66.00	12.00	
22	ANITA-MONROVIA	DU	66.00	16.00	
23	ANITA-MONROVIA	DU	66.00	4.00	
24	APL-LONG BEACH	DU	66.00	4.00	
25	APOLLO-HUNTINGTON BEACH	DU	66.00	12.00	
26	APPLE VALLEY-HI DESERT	DU	115.00	12.00	
27	AQUEDUCT-HI DESERT	DU	115.00	12.00	
28	ARCADIA-MONROVIA	DU	66.00	16.00	
29	ARCADIA-MONROVIA	DU	66.00	4.00	
30	ARCHIBALD-FOOTHILL	DU	66.00	12.00	
31	ARCHLINE-ONTARIO	DU	66.00	12.00	
32	ARCO-LONG BEACH	DU	66.00	12.00	
33	ARRO-SAN BERNARDINO	DU	33.00	4.00	
34	ARROWHEAD-ARROWHEAD	DU	115.00	33.00	
35	ARROWHEAD-ARROWHEAD	DU	33.00	12.00	
36	ARROYO-GLENDORA	DU	66.00	16.00	
37	ARROYO-GLENDORA	DU	16.00	4.00	
38	ASTRO-LONG BEACH	DU	66.00	12.00	
39	ATHENS-COMPTON	DU	16.00	4.00	
40	ATWOOD-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	AULD-SAN JACINTO	DU	115.00	33.00	
2	AULD-SAN JACINTO	DU	115.00	12.00	
3	AZUSA-AZUSA	DU	66.00	12.00	
4	BAIN-MIRA LOMA	DU	66.00	12.00	
5	BAKER-HI DESERT	DU	115.00	33.00	
6	BAKER-HI DESERT	DU	115.00	12.00	
7	BANDINI-COMPTON	DU	66.00	16.00	
8	BANNING-INLAND	DU	115.00	33.00	
9	BARSTOW-HI DESERT	DU	33.00	12.00	
10	BARTOLO-WHITTIER	DU	12.00	4.00	
11	BASSETT-COVINA	DU	66.00	12.00	
12	BASTA-FULLERTON	DU	12.00	4.00	
13	BAYSIDE-HUNTINGTON BEACH	DU	66.00	12.00	
14	BEAUMONT-INLAND	DU	12.00	4.00	
15	BEDFORD-SANTA MONICA	DU	16.00	4.00	
16	BELDING-PALM SPRINGS	DU	33.00	4.00	
17	BELMONT-LONG BEACH	DU	12.00	4.00	
18	BELVEDERE-MONTEBELLO	DU	16.00	4.00	
19	BEVERLY-SANTA MONICA	DU	66.00	16.00	
20	BEVERLY-SANTA MONICA	DU	66.00	4.00	
21	BICKNELL-MONTEBELLO	DU	16.00	4.00	
22	BIXBY-LONG BEACH	DU	12.00	4.00	
23	BLACK MOUNTAIN-APPLE VALLEY	DU	115.00	4.00	
24	BLISS-TULARE	DU	66.00	12.00	
25	BLOOMINGTON-FOOTHILL	DU	66.00	12.00	
26	BLUFF COVE-REDONDO	DU	16.00	4.00	
27	BLYTHE CITY-BLYTHE	DU	33.00	12.00	
28	BLYTHE CITY-BLYTHE	DU	33.00	4.80	
29	BOLSA-HUNTINGTON BEACH	DU	66.00	12.00	
30	BOOST-LONG BEACH	DU	66.00	12.00	
31	BORREGO-EL TORO	DU	66.00	12.00	
32	BOTTLE-CABAZON	DU	115.00	4.00	
33	BOVINE-LONG BEACH	DU	66.00	12.00	
34	BOWL-LONG BEACH	DU	66.00	12.00	
35	BOWL-LONG BEACH	DU	66.00	4.00	
36	BOXWOOD-PORTERVILLE	DU	66.00	12.00	
37	BRADBURY-MONROVIA	DU	66.00	16.00	
38	BREA-FULLERTON	DU	66.00	12.00	
39	BREEZE-LANCASTER	DU	66.00	12.00	
40	BREW-IRWINDALE	DU	66.00	4.00	

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1	BREWSTER-COMPTON	DU	16.00	4.00	
2	BRIDGE-REDONDO	DU	66.00	4.00	
3	BRIGHTON-REDONDO	DU	66.00	16.00	
4	BROADWAY-LONG BEACH	DU	66.00	12.00	
5	BROADWAY-LONG BEACH	DU	12.00	4.00	
6	BROOKHURST-HUNTINGTON BEACH	DU	66.00	12.00	
7	BROWNING-DELANO	DU	66.00	12.00	
8	BRYAN-SANTA ANA	DU	66.00	12.00	
9	BRYMAN-HI DESERT	DU	33.00	4.00	
10	BULLIS-COMPTON	DU	66.00	16.00	
11	BULLIS-COMPTON	DU	66.00	4.00	
12	BUNKER-SAN JACITO	DU	115.00	12.00	
13	BURNT MILL-LAKE ARROWHEAD	DU	33.00	12.00	
14	BURPIT-ORANGE	DU	66.00	4.00	
15	CABAZON-PALM SPRINGS	DU	33.00	12.00	
16	CABRILLO-EL TORO	DU	66.00	12.00	
17	CADY-HI DESERT	DU	33.00	12.00	
18	CAJALCO-PERRIS	DU	115.00	12.00	
19	CAL CEMENT-MOJAVE	DU	66.00	4.00	
20	CALCITY-CAL CITY	DU	33.00	12.00	
21	CALDEN-COMPTON	DU	66.00	16.00	
22	CALECTRIC-INLAND	DU	115.00	33.00	
23	CAMARILLO-VENTURA	DU	66.00	16.00	
24	CAMDEN-SANTA ANA	DU	66.00	12.00	
25	CAMERON-LONG BEACH	DU	66.00	12.00	
26	CANTIL-RIDGECREST	DU	33.00	12.00	
27	CANYON-FULLERTON	DU	66.00	12.00	
28	CANYON LAKE-SAN JACINTO	DU	33.00	12.00	
29	CAPITAN-SANTA BARBARA	DU	66.00	16.00	
30	CAPSULE-SAN BERNARDINO	DU	33.00	4.00	
31	CAPTIVE-DELANO	DU	66.00	12.00	
32	CARBOGEN-LONG BEACH	DU	66.00	12.00	
33	CARBONIC-CARSON	DU	66.00	12.00	
34	CARDIFF-INLAND	DU	66.00	12.00	
35	CARDIFF-INLAND	DU	66.00	4.00	
36	CARMENITA-WHITTIER	DU	66.00	12.00	
37	CARODEAN-TWENTY-NINE PALMS	DU	115.00	12.00	
38	CAROLINA-FULLERTON	DU	66.00	12.00	
39	CARPINTERIA-CARPINTERIA	DU	66.00	16.00	
40	CARSON-COMPTON	DU	66.00	16.00	

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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	CASITAS-VENTURA	DU	66.00	16.00	
2	CEDARWOOD-HUNTINGTON BEACH	DU	12.00	4.00	
3	CERTIFIED-LONG BEACH	DU	66.00	12.00	
4	CHANNEL ISLAND-TEHACHAPI	DU	66.00	16.00	
5	CHARMIN-OXNARD	DU	66.00	12.00	
6	CHARMIN-OXNARD	DU	66.00	4.00	
7	CHASE-ONTARIO	DU	66.00	12.00	
8	CHATHAM-VISALIA	DU	66.00	12.00	
9	CHATSWORTH-THOUSAND OAK	DU	66.00	16.00	
10	CHERRY-LONG BEACH	DU	66.00	12.00	
11	CHESTNUT-SANTA ANA	DU	66.00	12.00	
12	CHEVCENTRAL-EL SUGUNDO	DU	66.00	16.00	
13	CHIQUITA-EL TORO	DU	66.00	12.00	
14	CITRUS-COVINA	DU	66.00	12.00	
15	CLAREMONT-CLAREMONT	DU	66.00	4.00	
16	CLARK-LONG BEACH	DU	66.00	4.00	
17	COFFEE-PALM SPRINGS	DU	33.00	12.00	
18	COLONIA-VENTURA	DU	66.00	16.00	
19	COLORADO-SANTA MONICA	DU	66.00	16.00	
20	COLORADO-SANTA MONICA	DU	66.00	4.00	
21	COLOSSUS-VALENCIA	DU	66.00	16.00	
22	COLTON-FOOTHILL	DU	66.00	12.00	
23	COLTON CEMENT-COLTON	DU	66.00	12.00	
24	COLUMBINE-DELANO	DU	66.00	12.00	
25	COMPRESS-TORRANCE	DU	66.00	12.00	
26	COMPTON-COMPTON	DU	16.00	4.00	
27	CONCHO-PALM SPRINGS	DU	115.00	12.00	
28	CONVERSE FLATS-CAMP ANGELUS	DU	33.00	12.00	
29	CORNERS-LONG BEACH	DU	66.00	2.40	
30	CORNUTA-COMPTON	DU	66.00	12.00	
31	CORONA-ONTARIO	DU	66.00	33.00	
32	CORONA-ONTARIO	DU	66.00	12.00	
33	CORONA-ONTARIO	DU	33.00	4.00	
34	CORRECTION-TEHACHAPI	DU	66.00	12.00	
35	CORTEZ-COVINA	DU	66.00	12.00	
36	CORUM-LANCASTER	DU	66.00	12.00	
37	COSMIC-HAWTHORNE	DU	66.00	12.00	
38	COSO-LITTLE LAKE	DU	115.00	12.00	
39	COSTA MESA-HUNTINGTON BEACH	DU	12.00	4.00	
40	COTTONWOOD-HI DESERT	DU	115.00	33.00	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	CRATER-THOUSAND OAK	DU	66.00	16.00	
2	CREST-REDONDO	DU	66.00	16.00	
3	CRESTMORE-RUBIDOUX	DU	66.00	4.00	
4	CROWN-HUNTINGTON BEACH	DU	66.00	12.00	
5	CRYCO-INDUSTRY	DU	66.00	13.80	
6	CUCAMONGA-FOOTHILL	DU	66.00	12.00	
7	CUDAHY-COMPTON	DU	66.00	16.00	
8	CUDAHY-COMPTON	DU	66.00	4.00	
9	CULVER-SANTA MONICA	DU	66.00	16.00	
10	CULVER-SANTA MONICA	DU	66.00	4.00	
11	CUMMINGS-LANCASTER	DU	66.00	12.00	
12	CYBER-EL SEGUNDO	DU	66.00	12.00	
13	CYPRESS-FULLERTON	DU	66.00	12.00	
14	DAIRYMANS-TULARE	DU	66.00	12.00	
15	DAISY-LONG BEACH	DU	12.00	4.00	
16	DALTON-MONROVIA	DU	66.00	12.00	
17	DATABANK-CORONA	DU	66.00	12.00	
18	DECLEZ-FOOTHILL	DU	66.00	12.00	
19	DECLEZ-FOOTHILL	DU	12.00	4.00	
20	DEFRAIN-BLYTHE	DU	33.00	12.00	
21	DEL MAR-EL SEGUNDO	DU	66.00	13.20	
22	DEL ROSA-INLAND	DU	66.00	12.00	
23	DEL SUR-LANCASTER	DU	66.00	12.00	
24	DELANO-DELANO	DU	66.00	12.00	
25	DELANO-DELANO	DU	66.00	4.00	
26	DESAL-SANTA BARBARA	DU	66.00	12.00	
27	DESERT OUTPOST-CATHEDRAL CITY	DU	33.00	12.00	
28	DIAMOND BAR-COVINA	DU	66.00	12.00	
29	DIEMER-YORBA LINDA	DU	66.00	4.00	
30	DIKE-LONG BEACH	DU	66.00	12.00	
31	DITMAR-REDONDO	DU	66.00	16.00	
32	DITMAR-REDONDO	DU	16.00	4.00	
33	DOCK-LONG BEACH	DU	66.00	25.00	
34	DOHENY-SANTA MONICA	DU	16.00	4.00	
35	DOMHILL-CARSON	DU	66.00	4.00	
36	DOUGLAS-EL SEGUNDO	DU	66.00	16.00	
37	DOUGOIL-PARAMOUNT	DU	66.00	12.00	
38	DOWNEY-WHITTIER	DU	12.00	4.00	
39	DOWNEY MED-WHITTIER	DU	66.00	12.00	
40	DOWNS-RIDGECREST	DU	115.00	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	DUARTE-MONROVIA	DU	16.00	4.00	
2	DUNES-BLYTHE	DU	33.00	12.00	
3	DUNN SIDING-HI DESERT	DU	115.00	12.00	
4	EARLIMART-DELANO	DU	66.00	12.00	
5	EAST BARSTOW-HI DESERT	DU	33.00	4.00	
6	EATON-MONROVIA	DU	66.00	16.00	
7	EDINGER-SANTA ANA	DU	12.00	4.00	
8	EDWARDS-RIDGECREST	DU	115.00	33.00	
9	EISENHOWER-PALM SPRINGS	DU	115.00	33.00	
10	EISENHOWER-PALM SPRINGS	DU	115.00	12.00	
11	EL SOBRANTE-ONTARIO	DU	33.00	12.00	
12	ELCANS-VISALIA	DU	66.00	12.00	
13	ELIZABETH LAKE-VENTURA	DU	66.00	16.00	
14	ELSINORE-SAN JACINTO	DU	115.00	33.00	
15	ELSINORE-SAN JACINTO	DU	115.00	12.00	
16	ELY-FULLERTON	DU	66.00	12.00	
17	ERIC-LONG BEACH	DU	66.00	12.00	
18	ESTERO-VENTURA	DU	66.00	16.00	
19	ESTRELLA-EL TORO	DU	66.00	12.00	
20	EUCLID-ONTARIO	DU	12.00	4.00	
21	FAIR OAKS-MONROVIA	DU	16.00	4.00	
22	FAIRFAX-LOS ANGELES	DU	66.00	16.00	
23	FAIRFAX-LOS ANGELES	DU	16.00	4.00	
24	FAIRVIEW-SANTA ANA	DU	66.00	12.00	
25	FARRELL-PALM SPRINGS	DU	115.00	12.00	
26	FEDERALGEN-COMMERCE	DU	66.00	12.00	
27	FELTON-INGLEWOOD	DU	66.00	16.00	
28	FELTON-INGLEWOOD	DU	16.00	4.00	
29	FERNWOOD-COMPTON	DU	66.00	16.00	
30	FIBRE-RIVERSIDE	DU	66.00	4.00	
31	FILLMORE-VENTURA	DU	66.00	16.00	
32	FIREHOUSE-ONTARIO	DU	66.00	12.00	
33	FLORADAY-WHITTIER	DU	12.00	4.00	
34	FOGARTY-LITTLE LAKE	DU	115.00	12.00	
35	FOREST HOME-INLAND	DU	33.00	2.40	
36	FORGE-RANCHO CUCAMONGA	DU	66.00	12.00	
37	FORT IRWIN-FORT IRWIN	DU	33.00	12.00	
38	FRANCIS-ONTARIO	DU	66.00	12.00	
39	FRAZIER PARK-LANCASTER	DU	66.00	16.00	
40	FREMONT-COMPTON	DU	66.00	16.00	

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

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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	FREMONT-COMPTON	DU	16.00	4.00	
2	FRUITLAND-COMPTON	DU	66.00	16.00	
3	FRUITLAND-COMPTON	DU	66.00	4.00	
4	FUEL-LONG BEACH	DU	66.00	4.00	
5	FULLERTON-FULLERTON	DU	66.00	12.00	
6	FULLERTON-FULLERTON	DU	66.00	4.00	
7	GAGE-COMPTON	DU	16.00	4.00	
8	GALAXY-MANHATTAN BEACH	DU	66.00	12.00	
9	GALAXY-MANHATTAN BEACH	DU	66.00	4.00	
10	GALE-HI DESERT	DU	115.00	33.00	
11	GALLATIN-WHITTIER	DU	66.00	12.00	
12	GANESHA-COVINA	DU	66.00	16.00	
13	GANESHA-COVINA	DU	66.00	12.00	
14	GANESHA-COVINA	DU	12.00	4.00	
15	GARFIELD-EL MONTE	DU	66.00	4.00	
16	GARNET-PALM SPRINGS	DU	115.00	33.00	
17	GARNET-PALM SPRINGS	DU	33.00	12.00	
18	GARVEY-MONTEBELLO	DU	16.00	4.00	
19	GATX-CARSON	DU	66.00	12.00	
20	GAVILAN-SAN JACINTO	DU	33.00	12.00	
21	GAVIOTA-SANTA BARBARA	DU	66.00	16.00	
22	GENAMIC-RANCHO CUCAMONGA	DU	66.00	12.00	
23	GEORGE A.F.B.-ADELANTO	DU	33.00	4.00	
24	GETTY-VENTURA	DU	66.00	16.00	
25	GILBERT-FULLERTON	DU	66.00	12.00	
26	GISLER-HUNTINGTON BEACH	DU	66.00	12.00	
27	GLEN AVON-ONTARIO	DU	66.00	12.00	
28	GLEN IVY-GLEN IVY HOT	DU	33.00	12.00	
29	GLENNVILLE-DELANO	DU	66.00	12.00	
30	GOLDSTONE-BARSTOW	DU	33.00	12.00	
31	GOLDTOWN-LANCASTER	DU	66.00	12.00	
32	GONZALES-VENTURA	DU	66.00	16.00	
33	GORMAN-LANCASTER	DU	66.00	12.00	
34	GOSHEN-VISALIA	DU	66.00	12.00	
35	GRAHAM-COMPTON	DU	16.00	4.00	
36	GRANADA-MONTEBELLO	DU	16.00	4.00	
37	GREAT LAKES-ROSAMOND	DU	66.00	12.00	
38	GREENHORN-DELANO	DU	66.00	2.00	
39	GREENING-LONG BEACH	DU	66.00	12.00	
40	HAAGEN-TULARE	DU	66.00	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	HAMILTON-HUNTINGTON BEACH	DU	66.00	12.00	
2	HANFORD-HANFORD	DU	66.00	4.00	
3	HANJIN-LONG BEACH	DU	66.00	12.00	
4	HARVARD-HI DESERT	DU	33.00	12.00	
5	HASKELL-SAN FERNANDO	DU	66.00	16.00	
6	HATHAWAY-LONG BEACH	DU	66.00	12.00	
7	HATHAWAY-LONG BEACH	DU	66.00	4.00	
8	HAVASU-BLYTHE	DU	66.00	16.00	
9	HAVEDA-REDONDO	DU	16.00	4.00	
10	HAVILAH-KERNVILLE	DU	66.00	12.00	
11	HEDDA-LONG BEACH	DU	12.00	4.00	
12	HELENDALE-HI DESERT	DU	33.00	12.00	
13	HELIJET-PALMDALE	DU	66.00	12.00	
14	HEMET-SAN JACINTO	DU	33.00	12.00	
15	HESPERIA-HI DESERT	DU	115.00	12.00	
16	HI DESERT-TWENTY-NINE PALMS	DU	115.00	33.00	
17	HI DESERT-TWENTY-NINE PALMS	DU	34.50	24.94	
18	HIGHLAND-INLAND	DU	66.00	12.00	
19	HILLGEN-CITY OF INDUSTRY	DU	66.00	12.00	
20	HINKLEY-HI DESERT	DU	33.00	12.00	
21	HOLGATE-BORON	DU	33.00	12.00	
22	HOLIDAY-PALM SPRINGS	DU	33.00	4.00	
23	HOMART-INLAND	DU	115.00	12.00	
24	HOPEFUL-DUARTE	DU	66.00	12.00	
25	HOWARD-INGLEWOOD	DU	66.00	4.00	
26	HOYT-EL MONTE	DU	16.00	4.00	
27	HUGHESAIR-EL SEGUNDO	DU	66.00	12.00	
28	HUGHTRON-TORRANCE	DU	66.00	4.00	
29	HUNTINGTON PARK-COMPTON	DU	16.00	4.00	
30	HUSTON-ARROWHEAD	DU	33.00	12.00	
31	HUSTON-ARROWHEAD	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	IVAR-MONTEBELLO	DU	16.00	4.00	
8	IVYGLEN-ONTARIO	DU	115.00	12.00	
9	JEFFERSON-ONTARIO	DU	66.00	12.00	
10	JERSEY-COMPTON	DU	66.00	16.00	
11	JOSHUA TREE-TWENTY-NINE PALMS	DU	33.00	12.00	
12	KERNVILLE-KERNVILLE	DU	66.00	16.00	
13	KIMBALL-CHINO	DU	66.00	12.00	
14	LA CANADA-MONROVIA	DU	66.00	16.00	
15	LA CANADA-MONROVIA	DU	16.00	4.00	
16	LA HABRA-FULLERTON	DU	66.00	12.00	
17	LA MIRADA-WHITTIER	DU	66.00	12.00	
18	LA PALMA-FULLERTON	DU	66.00	12.00	
19	LA VETA-SANTA ANA	DU	66.00	12.00	
20	LAFAYETTE-HUNTINGTON BEACH	DU	66.00	12.00	
21	LAKEVIEW-NUEVO	DU	115.00	12.00	
22	LAKEWOOD-LONG BEACH	DU	66.00	4.00	
23	LAMPSON-SANTA ANA	DU	66.00	12.00	
24	LANCASTER-LANCASTER	DU	66.00	12.00	
25	LANCASTER-LANCASTER	DU	12.00	4.00	
26	LANDING-BLYTHE	DU	66.00	16.00	
27	LANPRI-LANCASTER	DU	66.00	12.00	
28	LARK ELLEN-COVINA	DU	66.00	12.00	
29	LAS LOMAS-IRVINE	DU	66.00	12.00	
30	LATIGO-THOUSAND OAK	DU	66.00	16.00	
31	LAUREL-TULARE	DU	66.00	12.00	
32	LAWNDALE-INGLEWOOD	DU	16.00	4.00	
33	LAYFAIR-COVINA	DU	66.00	12.00	
34	LAYFAIR-COVINA	DU	66.00	4.00	
35	LEATHERNECK-TWENTY-NINE PALMS	DU	115.00	34.50	
36	LEHMAN-OXNARD	DU	66.00	12.00	
37	LEMON COVE-VISALIA	DU	66.00	12.00	
38	LENNOX-INGLEWOOD	DU	66.00	17.00	
39	LENNOX-INGLEWOOD	DU	16.00	4.00	
40	LEVY-VENTURA	DU	66.00	16.00	

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1	LIBERTY-VISALIA	DU	66.00	12.00	
2	LIMESTONE-EL TORO	DU	66.00	12.00	
3	LINDEN-LONG BEACH	DU	12.00	4.00	
4	LINDSAY-PORTERVILLE	DU	66.00	12.00	
5	LIQUID-IRWINDALE	DU	66.00	4.00	
6	LITTLE ROCK-PALMDALE	DU	66.00	12.00	
7	LIVE OAK-COVINA	DU	66.00	12.00	
8	LOCKHEED-SAUGUS	DU	66.00	16.00	
9	LOCUST-LONG BEACH	DU	12.00	4.00	
10	LONGDON-COMPTON	DU	16.00	4.00	
11	LORAINE-LANCASTER	DU	66.00	12.00	
12	LOS CERRITOS-LONG BEACH	DU	66.00	12.00	
13	LOS CERRITOS-LONG BEACH	DU	12.00	4.00	
14	LOSULFUR-EL SEGUNDO	DU	66.00	13.20	
15	LUCAS-LONG BEACH	DU	66.00	12.00	
16	LUCAS-LONG BEACH	DU	66.00	4.00	
17	LUCERNE-HI DESERT	DU	33.00	12.00	
18	LUNADA-REDONDO	DU	16.00	4.00	
19	LYNWOOD-COMPTON	DU	66.00	4.00	
20	MACARTHUR-HUNTINGTON BEACH	DU	66.00	12.00	
21	MACNEIL-BURBANK	DU	66.00	12.00	
22	MADRID-REDONDO	DU	16.00	4.00	
23	MALIBU-THOUSAND OAK	DU	66.00	16.00	
24	MANHATTAN-REDONDO	DU	16.00	4.00	
25	MARASCHINO-INLAND	DU	115.00	12.00	
26	MARINE-SANTA MONICA	DU	66.00	16.00	
27	MARION-FULLERTON	DU	66.00	12.00	
28	MARIPOSA-DELANO	DU	66.00	12.00	
29	MARYMOUNT-REDONDO	DU	66.00	16.00	
30	MASCOT-HANFORD	DU	66.00	12.00	
31	MAXWELL-SAN JACINTO	DU	115.00	12.00	
32	MAYBERRY-SAN JACINTO	DU	115.00	12.00	
33	MAYFLOWER-MONROVIA	DU	16.00	4.00	
34	MENTONE-INLAND	DU	115.00	12.00	
35	MERCED-COVINA	DU	66.00	12.00	
36	MICHILLINDA-MONROVIA	DU	16.00	4.00	
37	MILITARY-TEMECULA	DU	33.00	12.00	
38	MILLIKEN-INLAND	DU	66.00	12.00	
39	MINNEOLA-HI DESERT	DU	33.00	12.00	
40	MISSILE-POINT MUGU	DU	66.00	16.00	

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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	MOBILE SUBSTATIONS-TORRANCE	DU	115.00	33.00	
2	MOBILE SUBSTATIONS-TORRANCE	DU	66.00	2.40	
3	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	4.00	
4	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	2.40	
5	MOBILE SUBSTATIONS-TORRANCE	DU	16.00	2.40	
6	MOBILE SUBSTATIONS-TORRANCE	DU	12.00	2.40	
7	MOBILOIL-TORRANCE	DU	66.00	12.00	
8	MOBILOIL-TORRANCE	DU	12.00	2.40	
9	MOBILOIL-TORRANCE	DU	12.00	0.48	
10	MODENA-SANTA ANA	DU	66.00	12.00	
11	MODOC-SANTA BARBARA	DU	16.00	4.00	
12	MONETA-REDONDO	DU	16.00	4.00	
13	MONOLITH-LANCASTER	DU	66.00	12.00	
14	MONROVIA-MONROVIA	DU	16.00	4.00	
15	MONTECITO-SANTA BARBARA	DU	16.00	4.00	
16	MOOG-TORRANCE	DU	66.00	12.00	
17	MORAGA-TEMECULA	DU	115.00	12.00	
18	MORENO-MORENO VALLEY	DU	115.00	12.00	
19	MORNINGSIDE-INGLEWOOD	DU	16.00	4.00	
20	MORRO-EL TORO	DU	66.00	12.00	
21	MOULTON-EL TORO	DU	66.00	12.00	
22	MOUNTAIN PASS-HI DESERT	DU	115.00	33.00	
23	MOUNTAIN PASS-HI DESERT	DU	33.00	12.00	
24	MOVIE-CULVER CITY	DU	66.00	16.00	
25	MT. VERNON-INLAND	DU	33.00	4.00	
26	MURPHY-WHITTIER	DU	66.00	12.00	
27	MURRIETTA 2-SAN JACINTO	DU	33.00	12.00	
28	MUSCOY-INLAND	DU	33.00	4.00	
29	NAOMI-COMPTON	DU	16.00	4.00	
30	NAPLES-LONG BEACH	DU	12.00	4.00	
31	NAROD-ONTARIO	DU	66.00	12.00	
32	NARROWS-WHITTIER	DU	66.00	12.00	
33	NATURAL-TWENTY-NINE PALMS	DU	66.00	12.00	
34	NAVY MOLE-LONG BEACH	DU	66.00	12.00	
35	NEENACH-LANCASTER	DU	66.00	12.00	
36	NELSON-SAN JACINTO	DU	115.00	33.00	
37	NELSON-SAN JACINTO	DU	115.00	12.00	
38	NEPTUNE-LONG BEACH	DU	66.00	12.00	
39	NEPTUNE-LONG BEACH	DU	66.00	4.00	
40	NEWBURY-THOUSAND OAK	DU	66.00	16.00	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/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	NEWCOMB-SAN JACINTO	DU	115.00	12.00	
2	NEWHALL-SAN FERNANDO	DU	66.00	16.00	
3	NEWMARK-MONTEBELLO	DU	66.00	16.00	
4	NEWMARK-MONTEBELLO	DU	66.00	4.00	
5	NIAGARA-RIALTO	DU	66.00	12.00	
6	NIAGRA-RIALTO	DU	66.00	12.00	
7	NIGUEL-EL TORO	DU	66.00	12.00	
8	NIGUEL-EL TORO	DU	66.00	4.00	
9	NOGALES-COVINA	DU	66.00	12.00	
10	NOLA-COMPTON	DU	66.00	16.00	
11	NORSEAL-SEAL BEACH	DU	66.00	12.00	
12	NORTH INTAKE-BLYTHE	DU	33.00	12.00	
13	NORTH MUROC-RIDGECREST	DU	33.00	12.00	
14	NORTH OAKS-SAN FERNANDO	DU	66.00	16.00	
15	NORTHROP-HAWTHORNE	DU	66.00	4.00	
16	NORTHWIND-LANCASTER	DU	66.00	12.00	
17	NORWELD-BREA	DU	66.00	12.00	
18	NUGGET-TWENTY-NINE PALMS	DU	34.90	24.90	
19	OAK GROVE-VISALIA	DU	66.00	12.00	
20	OAK PARK-THOUSAND OAK	DU	66.00	16.00	
21	OASIS-LANCASTER	DU	66.00	12.00	
22	OCEAN PARK-SANTA MONICA	DU	16.00	4.00	
23	OCEANVIEW-HUNTINGTON BEACH	DU	66.00	12.00	
24	OCTOL-TULARE	DU	66.00	12.00	
25	OJAI-VENTURA	DU	66.00	16.00	
26	OLDFIELD-LONG BEACH	DU	12.00	4.00	
27	OLIVE LAKE-BLYTHE	DU	33.00	12.00	
28	OLYMPIC-SANTA MONICA	DU	16.00	4.00	
29	ONEILL-RANCHO SANTA	DU	66.00	12.00	
30	ONSHORE-ELLWOOD	DU	66.00	12.00	
31	ORANGE-SANTA ANA	DU	66.00	12.00	
32	ORCOGEN-HUNTINGTON BEACH	DU	66.00	12.00	
33	ORCOSAN-FOUNTAIN VALLEY	DU	66.00	12.00	
34	ORDWAY-HI DESERT	DU	33.00	12.00	
35	ORO GRANDE-HI DESERT	DU	33.00	12.00	
36	ORTEGA-SANTA BARBARA	DU	66.00	33.00	2.40
37	PACLINE-CARSON	DU	66.00	2.40	
38	PALM CANYON-PALM SPRINGS	DU	33.00	12.00	
39	PALM CANYON-PALM SPRINGS	DU	33.00	4.00	
40	PALM SPRINGS-PALM SPRINGS	DU	33.00	4.00	

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

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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	PALM VILLAGE-PALM SPRINGS	DU	33.00	12.00	
2	PALMDALE-LANCASTER	DU	66.00	12.00	
3	PALOS VERDES-REDONDO	DU	16.00	4.00	
4	PAPER-FULLERTON	DU	66.00	4.00	
5	PARKWOOD-FULLERTON	DU	66.00	12.00	
6	PASSONS-WHITTIER	DU	66.00	12.00	
7	PAUBA-SAN JACINTO	DU	115.00	12.00	
8	PAULARINO-HUNTINGTON BEACH	DU	12.00	4.00	
9	PEARL-SANTA MONICA	DU	16.00	4.00	
10	PECHANGA-SAN JACINTO	DU	115.00	33.00	
11	PECHANGA-SAN JACINTO	DU	115.00	12.00	
12	PEDLEY-ONTARIO	DU	66.00	12.00	
13	PEERLESS-RIDGECREST	DU	33.00	12.00	
14	PEPPER-INLAND	DU	115.00	12.00	
15	PEREZ-ONTARIO	DU	33.00	4.00	
16	PERRY-REDONDO	DU	16.00	4.00	
17	PEYTON-ONTARIO	DU	66.00	12.00	
18	PHARMACY-THOUSAND OAK	DU	66.00	16.00	
19	PHELAN-HI DESERT	DU	115.00	33.00	
20	PHELAN-HI DESERT	DU	115.00	12.00	
21	PICO-LONG BEACH	DU	66.00	12.00	
22	PIER-LONG BEACH	DU	66.00	12.00	
23	PIERPONT-VENTURA	DU	16.00	4.00	
24	PIONEER-WHITTIER	DU	66.00	12.00	
25	PIONEER-WHITTIER	DU	12.00	4.00	
26	PIPE-ETIWANDA	DU	66.00	12.00	
27	PITCHGEN-SAUGUS	DU	66.00	12.00	
28	PIUTE-LANCASTER	DU	66.00	12.00	
29	PIXLEY-DELANO	DU	66.00	12.00	
30	PLACENTIA-FULLERTON	DU	66.00	12.00	
31	PLASTER-SOUTH GATE	DU	66.00	2.40	
32	PLASTIC-CHINO	DU	66.00	12.00	
33	PLAYA-SANTA BARBARA	DU	16.00	4.00	
34	POLARIS-EL SEGUNDO	DU	66.00	4.00	
35	POLARIS-EL SEGUNDO	DU	16.00	4.00	
36	POMONA-COVINA	DU	12.00	4.00	
37	POPLAR-PORTERVILLE	DU	66.00	12.00	
38	PORTERVILLE-PORTERVILLE	DU	66.00	12.00	
39	PORTERVILLE-PORTERVILLE	DU	66.00	4.00	
40	PORTERVILLE-PORTERVILLE	DU	12.00	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	POTRERO-THOUSAND OAK	DU	66.00	16.00	
2	PROCESS-LONG BEACH	DU	66.00	12.00	
3	PROCGEN-OXNARD	DU	66.00	12.00	
4	PROCTOR-COMPTON	DU	66.00	12.00	
5	PROTEIN-TULARE	DU	66.00	12.00	
6	PUENTE-COVINA	DU	66.00	12.00	
7	PUREWATER-REDLANDS	DU	115.00	4.00	
8	QUARTZ HILL-LANCASTER	DU	66.00	12.00	
9	QUINN-DELANO	DU	66.00	12.00	
10	RAILROAD-COVINA	DU	66.00	12.00	
11	RALPHS-COMPTON	DU	66.00	4.00	
12	RAMONA-MONTEBELLO	DU	66.00	4.00	
13	RANCHO-HI DESERT	DU	33.00	12.00	
14	RANDALL-FOOTHILL	DU	66.00	12.00	
15	RANDOLPH-COMPTON	DU	66.00	16.00	
16	RANDSBURG-RIDGECREST	DU	115.00	33.00	
17	RAVENDALE-MONTEBELLO	DU	66.00	16.00	
18	RAVENDALE-MONTEBELLO	DU	66.00	4.00	
19	RECOVERY-HUNTINGTON BEACH	DU	66.00	12.00	
20	RECTIFIER-TEMECULA	DU	115.00	33.00	
21	REDLANDS-INLAND	DU	66.00	12.00	
22	REDLANDS-INLAND	DU	66.00	4.00	
23	REDMAN-LANCASTER	DU	66.00	12.00	
24	REDONDO-REDONDO	DU	16.00	4.00	
25	REDUCTION-ETIWANDA	DU	66.00	12.00	
26	REDUCTION-ETIWANDA	DU	66.00	4.00	
27	REFINERY-CARSON	DU	66.00	12.00	
28	REFUSE-COMMERCE	DU	66.00	12.00	
29	RENO-INDUSTRY	DU	66.00	4.00	
30	REPETTO-MONTEBELLO	DU	66.00	16.00	
31	REPETTO-MONTEBELLO	DU	66.00	4.00	
32	RIALTO-FOOTHILL	DU	33.00	12.00	
33	RIALTO-FOOTHILL	DU	33.00	4.00	
34	RIDGECREST-RIDGECREST	DU	33.00	4.80	
35	RINGMILL-PARAMOUNT	DU	66.00	4.00	
36	RINDGE-MALIBU	DU	66.00	16.00	
37	RIPLEY-BLYTHE	DU	33.00	12.00	
38	RITEAID-LANCASTER	DU	66.00	12.00	
39	RITTER RANCH-PALMDALE	DU	66.00	12.00	
40	RIVERA-WHITTIER	DU	12.00	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	RIVERTEX-ORO GRANDE	DU	115.00	13.80	
2	RIVERWAY-VISALIA	DU	66.00	12.00	
3	ROADWAY-HI DESERT	DU	115.00	12.00	
4	ROCKAIR-PALMDALE	DU	66.00	12.00	
5	ROCKET TEST-BORON	DU	115.00	33.00	
6	ROLLING HILLS-REDONDO	DU	66.00	16.00	
7	ROLLING HILLS-REDONDO	DU	66.00	4.00	
8	ROSAMOND-LANCASTER	DU	66.00	16.00	
9	ROSAMOND-LANCASTER	DU	66.00	12.00	
10	ROSECRANS-EL SEGUNDO	DU	66.00	16.00	
11	ROSEMEAD-MONTEBELLO	DU	66.00	16.00	
12	ROYAL-SIMI VALLEY	DU	66.00	16.00	
13	RUBIDOUX-RUBIDOUX	DU	33.00	12.00	
14	RUBIDOUX-RUBIDOUX	DU	33.00	4.00	
15	RUNNING SPRINGS-ARROWHEAD	DU	33.00	12.00	
16	RUSH-MONTEBELLO	DU	66.00	16.00	
17	SAN ANTONIO-COVINA	DU	66.00	12.00	
18	SAN DIMAS-COVINA	DU	66.00	12.00	
19	SAN FERNANDO-SAN FERNANDO	DU	66.00	16.00	
20	SAN GABRIEL-MONTEBELLO	DU	66.00	4.00	
21	SAN MARCOS-SANTA BARBARA	DU	66.00	16.00	
22	SAN MARINO-MONROVIA	DU	16.00	4.00	
23	SAN MIGUEL-VENTURA	DU	66.00	16.00	
24	SAN VICENTE-SANTA MONICA	DU	16.00	4.00	
25	SANIGEN-WALNUT	DU	66.00	12.00	
26	SANTA BARBARA-SANTA BARBARA	DU	66.00	16.00	
27	SANTA BARBARA-SANTA BARBARA	DU	66.00	4.00	
28	SANTA FE SPRINGS-WHITTIER	DU	66.00	12.00	
29	SANTA MONICA-SANTA MONICA	DU	66.00	16.00	
30	SANTA MONICA-SANTA MONICA	DU	66.00	4.00	
31	SANTA ROSA-PALM SPRINGS	DU	115.00	33.00	
32	SANTA ROSA-PALM SPRINGS	DU	115.00	12.00	
33	SANTA SUSANA-THOUSAND OAK	DU	66.00	16.00	
34	SANTEE-INDUSTRY	DU	66.00	12.00	
35	SATICOY-VENTURA	DU	66.00	16.00	
36	SAVAGE-HESPERIA	DU	115.00	12.00	
37	SAWTELLE-SANTA MONICA	DU	66.00	16.00	
38	SEABRIGHT-LONG BEACH	DU	66.00	12.00	
39	SEARLES-RIDGECREST	DU	115.00	33.00	
40	SECOND AVENUE-BLYTHE	DU	33.00	12.00	

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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	SEPULVEDA-INGLEWOOD	DU	66.00	16.00	
2	SERRFGEN-LONG BEACH	DU	66.00	12.00	
3	SERVER-EL SEGUNDO	DU	66.00	16.00	
4	SHANDIN-INLAND	DU	115.00	12.00	
5	SHAWNEE-HUNTINGTON BEACH	DU	66.00	12.00	
6	SHELLSOM-SOMIS	DU	66.00	2.40	
7	SHELLWATT-CARSON	DU	66.00	12.00	
8	SHIP-LONG BEACH	DU	66.00	12.00	
9	SHRED-SOUTHGATE	DU	66.00	12.00	
10	SHULTZ-SOUTH GATE	DU	66.00	16.00	
11	SHUTTLE-LANCASTER	DU	66.00	12.00	
12	SIERRA MADRE-MONROVIA	DU	16.00	4.00	
13	SIGGEN-NORWALK	DU	66.00	12.00	
14	SIGNAL HILL-LONG BEACH	DU	66.00	12.00	
15	SIGNAL HILL-LONG BEACH	DU	12.00	4.00	
16	SILVER SPUR-PALM SPRINGS	DU	33.00	12.00	
17	SIMPSON PAPER-FULLERTON	DU	66.00	4.00	
18	SIXTEENTH STREET-INLAND	DU	33.00	12.00	
19	SKINWATER-WINCHESTER	DU	33.00	4.00	
20	SKYLARK-SAN JACINTO	DU	115.00	12.00	
21	SLATER-HUNTINGTON BEACH	DU	66.00	12.00	
22	SMILEY-INLAND	DU	12.00	4.00	
23	SOCO-HUNTINGTON BEACH	DU	66.00	33.00	
24	SOLEMINT-SAN FERNANDO	DU	66.00	16.00	
25	SOMERSET-COMPTON	DU	66.00	12.00	
26	SOMERSET-COMPTON	DU	66.00	4.00	
27	SOMIS-VENTURA	DU	66.00	16.00	
28	SONY-CULVER CITY	DU	66.00	16.00	
29	SOPIPE-INDUSTRY	DU	66.00	4.00	
30	SOQUEL-CHINO HILLS	DU	66.00	12.00	
31	SOUTH GATE-COMPTON	DU	16.00	4.00	
32	SOUTHBASE-E.A.F.B.	DU	115.00	33.00	
33	SPACE-REDONDO BEACH	DU	66.00	4.00	
34	SPONGE-PICO RIVERA	DU	66.00	2.40	
35	STADIUM-LONG BEACH	DU	66.00	12.00	
36	STADLER-SAN JACINTO	DU	115.00	12.00	
37	STANHILL-INGLEWOOD	DU	66.00	12.00	
38	STATE STREET-LONG BEACH	DU	66.00	12.00	
39	STENT-TEMECULA	DU	115.00	12.00	
40	STETSON-SAN JACINTO	DU	115.00	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	STEVEDORE-LONG BEACH	DU	66.00	12.00	
2	STEWART-WHITTIER	DU	66.00	12.00	
3	STODDARD-INLAND	DU	33.00	4.00	
4	STRATHMORE-PORTERVILLE	DU	66.00	12.00	
5	SULLIVAN-SANTA ANA	DU	66.00	12.00	
6	SULLIVAN-SANTA ANA	DU	66.00	4.00	
7	SUN CITY-SAN JACINTO	DU	115.00	12.00	
8	SUNNY DUNES-PALM SPRINGS	DU	33.00	4.00	
9	SUNNYHILLS-FULLERTON	DU	66.00	12.00	
10	SUNNYSIDE-LONG BEACH	DU	66.00	12.00	
11	SUNNYSIDE-LONG BEACH	DU	66.00	4.00	
12	TAHITI-SANTA MONICA	DU	66.00	16.00	
13	TAHITI-SANTA MONICA	DU	66.00	12.00	
14	TALBERT-SANTA ANA	DU	66.00	12.00	
15	TAMARISK-PALM SPRINGS	DU	115.00	12.00	
16	TAPIA-THOUSAND OAK	DU	66.00	16.00	
17	TEAM-WESTMINSTER	DU	66.00	12.00	
18	TELEGRAPH-WHITTIER	DU	66.00	12.00	
19	TEMPLE-MONROVIA	DU	16.00	4.00	
20	TENAJA-MURRIETA	DU	115.00	12.00	
21	TENNESSEE-INLAND	DU	66.00	12.00	
22	TERRA BELLA-PORTERVILLE	DU	66.00	12.00	
23	TERRACE-MONTEBELLO	DU	16.00	4.00	
24	THORNHILL-PALM SPRINGS	DU	115.00	12.00	
25	THOUSAND OAKS-THOUSAND OAK	DU	66.00	16.00	
26	THREE RIVERS-VISALIA	DU	66.00	12.00	
27	THRIVE-FONTANA	DU	66.00	12.00	
28	THRUST-CHATSWORTH	DU	66.00	4.00	
29	THUMS ISLAND ABCD-ISLAND GRISSOM-LONG BEACH	DU	66.00	4.00	
30	THUNDERBIRD-PALM SPRINGS	DU	33.00	4.80	
31	TIDELANDS-LONG BEACH	DU	66.00	12.00	
32	TIEFORT-HI DESERT	DU	115.00	33.00	
33	TIMBERWINE-BIG CREEK	DU	33.00	12.00	
34	TIMOTEO-INLAND	DU	66.00	12.00	
35	TIPPECANOE-INLAND	DU	12.00	4.00	
36	TIPTON-TULARE	DU	66.00	12.00	
37	TOPAZ-REDONDO	DU	66.00	4.00	
38	TORRANCE-REDONDO	DU	66.00	16.00	
39	TORREY-PIRU	DU	66.00	16.00	
40	TORTILLA-HI DESERT	DU	115.00	33.00	

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/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	TORTILLA-HI DESERT	DU	115.00	12.00	
2	TOYOTA-LONG BEACH	DU	66.00	12.00	
3	TRASK-SANTA ANA	DU	66.00	12.00	
4	TRITON-RANCHO PALO VERDE	DU	115.00	12.00	
5	TRONA-RIDGECREST	DU	33.00	12.00	
6	TROPHY-COVINA	DU	66.00	12.00	
7	TULARE-TULARE	DU	66.00	12.00	
8	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	12.00	
9	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	4.80	
10	UNIOIL-OXNARD	DU	66.00	16.00	
11	UNIVERSAL-UNIVERSAL CITY	DU	66.00	12.00	
12	UPLAND-FOOTHILL	DU	66.00	12.00	
13	UPLAND-FOOTHILL	DU	66.00	4.00	
14	VAIL-MONTEBELLO	DU	66.00	16.00	
15	VALDEZ-THOUSAND OAK	DU	66.00	16.00	
16	VEGAS-SANTA BARBARA	DU	66.00	16.00	
17	VENICE HILL-VISALIA	DU	66.00	12.00	
18	VENIDA-VISALIA	DU	66.00	12.00	
19	VERA-SANTA ANA	DU	66.00	12.00	
20	VERDANT-BLYTHE	DU	33.00	12.00	
21	VICTORIA-REDONDO	DU	66.00	16.00	
22	VICTORVILLE-HI DESERT	DU	33.00	12.00	
23	VICTORVILLE-HI DESERT	DU	33.00	4.00	
24	VISALIA-VISALIA	DU	66.00	12.00	
25	WABASH-MONTEBELLO	DU	66.00	12.00	
26	WAKEFIELD-VENTURA	DU	66.00	16.00	
27	WALKER BASIN-KERNVILLE	DU	66.00	12.00	
28	WALTERIA-REDONDO	DU	66.00	16.00	
29	WALTERIA-REDONDO	DU	66.00	4.00	
30	WASHINGTON-SANTA ANA	DU	66.00	12.00	
31	WASTEWATER-OXNARD	DU	66.00	16.00	
32	WATSON-COMPTON	DU	66.00	12.00	
33	WAVE-HUNTINGTON BEACH	DU	66.00	12.00	
34	WELDON-KERNVILLE	DU	66.00	12.00	
35	WESBASIN-EL SEGUNDO	DU	66.00	16.00	
36	WEST BARSTOW-HI DESERT	DU	33.00	4.00	
37	WEST RIVERSIDE-ONTARIO	DU	33.00	12.00	
38	WESTEX-SIGNAL HILL	DU	66.00	12.00	
39	WESTHILL-EL SEGUNDO	DU	66.00	16.00	
40	WESTPAC-GORMAN	DU	66.00	4.00	

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	04/14/2021	End of 2020/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	WEYMOUTH-LA VERNE	DU	66.00	4.00	
2	WHARF-LONG BEACH	DU	66.00	12.00	
3	WHEATLAND-DELANO	DU	66.00	12.00	
4	WHIPPLE-BLYTHE	DU	66.00	33.00	
5	WHITEWATER-PALM SPRINGS	DU	33.00	4.00	
6	WILLAMETTE-OXNARD	DU	66.00	12.00	
7	WILSONA-LANCASTER	DU	66.00	12.00	
8	WIMBLEDON-FOOTHILL	DU	66.00	12.00	
9	WINDSOR HILLS-INGLEWOOD	DU	66.00	16.00	
10	WINDSOR HILLS-INGLEWOOD	DU	16.00	4.00	
11	WOODRUFF-COMPTON	DU	12.00	4.00	
12	WOODVILLE-PORTERVILLE	DU	66.00	12.00	
13	WRIGHTWOOD-HI DESERT	DU	33.00	12.00	
14	WRIGHTWOOD-HI DESERT	DU	12.00	2.40	
15	YERMO-HI DESERT	DU	33.00	12.00	
16	YORBA LINDA-FULLERTON	DU	66.00	12.00	
17	YUCAIPA-INLAND	DU	66.00	12.00	
18	YUCCA-TWENTY-NINE PALMS	DU	115.00	12.00	
19	YUKON-INGLEWOOD	DU	66.00	16.00	
20	YUKON-INGLEWOOD	DU	66.00	4.00	
21	ZANJA-YUCAIPA	DU	115.00	33.00	
22					
23					
24	NOTE:				
25	TU - Transmission Unattended				
26	TA - Transmission Attended				
27	DU - Distribution Unattended				
28	DA - Distribution Attended				
29					
30	Summary: Capacity:				
31	739 DU 32504				
32	27 TA 27308				
33	135 TU 54409				
34	901 114221				
35					
36					
37					
38					
39					
40					

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2611	7					1
1120	4					2
560	2					3
840	3					4
112	4		*PEAKER	1	75	5
13	1					6
840	3					7
84	3		*PEAKER	1	75	8
332	2		*CUSTOMER SUBSTATION			9
99	3		*CUSTOMER SUBSTATION			10
90	3		*CUSTOMER SUBSTATION			11
1090	4					12
120	6	1				13
80	4					14
5	1		MOBIL GENERATOR	1	1	15
1119	3					16
84	3					17
3	1	1				18
1120	4					19
56	2					20
2238	6	1				21
330	3	1				22
810	3	2				23
56	2					24
280	1					25
144	1					26
133	1					27
14	1	1				28
560	2					29
500	2					30
56	2					31
560	2					32
112	4					33
2115	11					34
1120	4					35
45	2					36
560	2					37
56	2					38
6	3					39
560	2					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	2					1
14	1					2
840	3					3
100	2		*PHASE SHIFTER	1	56	4
560	2					5
810	3					6
73	3					7
500	2					8
56	2					9
2	3	1				10
840	3					11
1030	4					12
112	2					13
1090	4					14
56	2					15
840	3					16
45	2					17
2238	6	1				18
840	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	1					28
840	3					29
112	4					30
2238	6	1				31
1120	4	1				32
200	3	1				33
1120	4					34
200	3	1				35
57	3					36
44	2					37
13	1					38
1119	3	1				39
560	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) 04/14/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
560	2					1
40	2					2
78	3					3
810	3					4
56	2					5
280	1					6
560	2					7
1060	4					8
56	2					9
157	6					10
1090	4					11
112	4					12
3357	9	2				13
560	2		TEMPORARY BANK	1	280	14
28	1					15
2800	5					16
73	3					17
530	2					18
41	2					19
40	7					20
1120	4					21
162	3					22
112	4					23
560	2					24
56	2					25
780	3					26
90	4					27
4476	12	1				28
504	2					29
1090	4	1				30
840	3					31
100	4					32
560	2					33
116	2					34
14	1					35
10	1					36
60	1					37
80	4					38
120	1					39
229	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	04/14/2021	End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
44	1					1
133	1	1				2
1	6					3
84	1					4
21	1					5
65	1		*CUSTOMER SUBSTATION			6
168	3					7
158	2					8
5	3					9
250	1					10
720	2					11
1120	4					12
270	6	1				13
163	1					14
112	4					15
24	2					16
1	1					17
4	1					18
2	1					19
4	3	1				20
38	4					21
50	6	1				22
14	2					23
4	1					24
180	2					25
75	1		*CUSTOMER SUBSTATION			26
14	1		*CUSTOMER SUBSTATION			27
100	1					28
7	2					29
11	8	1				30
2	3	1				31
21	1					32
11	1					33
20	1		*CUSTOMER SUBSTATION			34
14	1					35
4	1					36
3	1					37
14	1		*CUSTOMER SUBSTATION			38
56	2		*CUSTOMER SUBSTATION			39
3117	9	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) 04/14/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3996	12	2				1
560	2					2
56	2					3
14	1		*CUSTOMER SUBSTATION			4
22	1		*CUSTOMER SUBSTATION			5
129	5					6
56	2					7
101	4					8
112	4					9
21	4	1				10
13	2					11
56	2					12
76	3					13
24	6	1				14
14	2					15
2	3	1				16
3	1					17
28	1		*CUSTOMER SUBSTATION			18
10	1		*CUSTOMER SUBSTATION			19
80	4		*CUSTOMER SUBSTATION			20
73	3					21
84	3					22
21	2					23
14	1		*CUSTOMER SUBSTATION			24
22	1		*CUSTOMER SUBSTATION			25
84	3					26
84	3					27
96	4					28
28	2					29
73	3					30
101	4					31
7	1		*CUSTOMER SUBSTATION			32
24	2					33
56	2					34
6	2	1				35
84	3					36
3	3	1				37
27	2					38
8	1					39
50	2					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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)	
112	2					1
112	4					2
84	4					3
56	2					4
8	1					5
5	3	1				6
84	3					7
101	3					8
11	2					9
6	3					10
81	3					11
11	1					12
84	3					13
6	1					14
25	4					15
9	1	1				16
10	1					17
10	1					18
168	6					19
38	3					20
11	1					21
8	1					22
27	2		*CUSTOMER SUBSTATION			23
56	2					24
112	4					25
11	4					26
28	2					27
25	2					28
40	2					29
28	1		*CUSTOMER SUBSTATION			30
84	3					31
28	1		*CUSTOMER SUBSTATION			32
56	2					33
42	2					34
14	2					35
28	1					36
100	4					37
64	3					38
45	2					39
19	1		*CUSTOMER SUBSTATION			40

SUBSTATIONS (Continued)

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21	2					1
23	2					2
56	2					3
56	2					4
4	2					5
45	2					6
56	2					7
101	4					8
1	3					9
78	3					10
12	6					11
84	3					12
14	2					13
14	1		*CUSTOMER SUBSTATION			14
19	2					15
104	6					16
5	3	1				17
73	3					18
45	2		*CUSTOMER SUBSTATION			19
42	3					20
28	2					21
112	4					22
73	3					23
45	2					24
56	2					25
4	3	1				26
53	3					27
14	1					28
28	2					29
6	3		*CUSTOMER SUBSTATION			30
11	1		*CUSTOMER SUBSTATION			31
56	2		*CUSTOMER SUBSTATION			32
6	1		*CUSTOMER SUBSTATION			33
101	4					34
112	2					35
84	3					36
42	2					37
101	4					38
48	2					39
66	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) 04/14/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2					1
6	3	1				2
11	1		*CUSTOMER SUBSTATION			3
56	2					4
67	2		*CUSTOMER SUBSTATION			5
22	1		*CUSTOMER SUBSTATION			6
112	4					7
28	1	1				8
56	3					9
45	2					10
101	4					11
168	4		*CUSTOMER SUBSTATION			12
104	4					13
95	4					14
28	1		*CUSTOMER SUBSTATION			15
20	2					16
56	4					17
84	3					18
84	3					19
9	3	1				20
14	1		*CUSTOMER SUBSTATION			21
56	2					22
30	6		*CUSTOMER SUBSTATION			23
28	1					24
112	4		*CUSTOMER SUBSTATION			25
13	2					26
56	2					27
1	3	1				28
5	1		*CUSTOMER SUBSTATION			29
56	2					30
112	2					31
134	5					32
3	2					33
8	1		*CUSTOMER SUBSTATION			34
101	4					35
14	1					36
28	1		*CUSTOMER SUBSTATION			37
13	2					38
15	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	04/14/2021	End of 2020/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	2					1
56	2					2
25	2		*CUSTOMER SUBSTATION			3
92	6					4
17	1					5
118	5					6
96	4					7
25	7					8
70	3					9
21	4	1				10
28	1	4				11
22	1		*CUSTOMER SUBSTATION			12
73	3					13
22	1		*CUSTOMER SUBSTATION			14
7	1					15
56	2					16
14	1		*CUSTOMER SUBSTATION			17
101	4					18
7	1					19
7	1					20
45	2		*CUSTOMER SUBSTATION			21
112	4					22
56	2					23
84	3					24
6	3	1				25
14	1		*CUSTOMER SUBSTATION			26
10	2					27
45	2					28
10	1		*CUSTOMER SUBSTATION			29
45	2		*CUSTOMER SUBSTATION			30
45	2					31
17	4					32
100	3		*CUSTOMER SUBSTATION			33
69	3					34
14	1		*CUSTOMER SUBSTATION			35
28	2		*CUSTOMER SUBSTATION			36
28	1		*CUSTOMER SUBSTATION			37
15	4					38
14	1		*CUSTOMER SUBSTATION			39
84	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) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
14	1					2
5	3					3
42	2					4
4	3	1				5
56	2					6
10	2					7
50	4					8
112	2					9
45	2					10
28	2					11
11	1					12
84	3					13
112	2					14
56	2					15
106	4					16
73	3					17
45	2					18
112	4					19
6	3	1				20
15	2					21
78	3					22
12	6	1				23
96	4					24
112	4					25
45	2		*CUSTOMER SUBSTATION			26
45	2					27
9	4					28
48	2					29
22	1		*CUSTOMER SUBSTATION			30
50	2					31
101	4					32
14	2					33
56	2					34
1	3	1				35
14	1		*CUSTOMER SUBSTATION			36
22	1					37
93	4					38
28	1	1				39
65	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) (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.
21	2					1
56	2					2
9	3	1				3
11	1		*CUSTOMER SUBSTATION			4
94	4					5
9	3	1				6
8	3	1				7
14	1		*CUSTOMER SUBSTATION			8
14	1		*CUSTOMER SUBSTATION			9
53	4	1				10
45	2					11
28	1					12
56	2	1				13
6	3					14
9	3	1				15
224	4					16
14	1					17
21	2					18
14	1		*CUSTOMER SUBSTATION			19
28	2					20
22	1					21
41	2					22
15	2					23
22	1		*CUSTOMER SUBSTATION			24
90	4					25
100	4					26
78	3					27
6	1					28
4	3	1				29
4	1					30
56	2					31
84	3					32
28	1					33
42	2					34
7	1					35
11	2					36
19	1					37
1	1	1				38
45	2					39
6	1		*CUSTOMER SUBSTATION			40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2					1
112	4					2
14	1		*CUSTOMER SUBSTATION			3
4	1					4
101	4					5
42	2					6
14	1	1				7
6	1					8
6	3	1				9
3	1					10
11	1					11
25	2					12
56	2		*CUSTOMER SUBSTATION			13
25	2					14
56	2					15
56	2					16
28	2					17
101	4					18
56	2		*CUSTOMER SUBSTATION			19
14	2					20
5	1					21
18	2					22
56	3					23
25	2		*CUSTOMER SUBSTATION			24
28	2					25
17	2					26
56	2		*CUSTOMER SUBSTATION			27
14	1		*CUSTOMER SUBSTATION			28
21	2					29
11	2					30
5	1					31
48	2					32
21	2					33
112	4					34
101	4					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	04/14/2021	End of 2020/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)	
56	2	1				1
2	3	1				2
5	3					3
101	4					4
28	1	1				5
48	2					6
11	1					7
56	2					8
112	4					9
78	3					10
5	1					11
9	4	1				12
84	3					13
45	2					14
15	2					15
101	4					16
56	2					17
78	3					18
98	4					19
73	3					20
56	2					21
25	2					22
78	3					23
90	4					24
6	6	1				25
22	1	1				26
10	1		*CUSTOMER SUBSTATION			27
84	3					28
56	2					29
56	2					30
56	2					31
6	3					32
73	3					33
7	1					34
84	3					35
28	1		*CUSTOMER SUBSTATION			36
28	1					37
56	2					38
14	4					39
48	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
112	4					1
149	6					2
11	1					3
56	2					4
11	1		*CUSTOMER SUBSTATION			5
56	2					6
76	3					7
56	2		*CUSTOMER SUBSTATION			8
20	2					9
14	1					10
3	3	1				11
40	2					12
8	3					13
67	3		*CUSTOMER SUBSTATION			14
56	2					15
15	6					16
28	2					17
6	3	1				18
21	2					19
101	4					20
15	2					21
8	3	1				22
56	2					23
6	3					24
84	3					25
56	2					26
81	4					27
20	1	1				28
20	2					29
56	2					30
90	4					31
106	4					32
11	2					33
28	2					34
62	3					35
15	2					36
14	1					37
112	4					38
11	2					39
22	1		*CUSTOMER SUBSTATION			40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
64	2					1
17	1					2
10	1					3
5	1					4
1	1					5
1	1					6
168	6		*CUSTOMER SUBSTATION			7
38	20		*CUSTOMER SUBSTATION			8
19	19		*CUSTOMER SUBSTATION			9
101	4					10
12	6	1				11
15	6					12
56	3					13
17	2					14
6	3	1				15
7	1		*CUSTOMER SUBSTATION			16
112	4					17
45	2					18
6	3					19
42	2					20
90	4					21
28	2					22
9	2					23
45	2					24
25	2					25
45	2					26
28	2					27
4	6	1				28
7	1					29
12	6					30
101	4					31
106	4					32
56	2					33
25	1		*CUSTOMER SUBSTATION			34
28	1					35
106	2					36
73	3					37
45	2					38
25	2					39
101	4					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	04/14/2021	End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
112	4					1
112	4					2
28	2					3
20	4	1				4
28	1					5
28	1					6
84	3					7
11	1					8
101	4					9
45	2					10
28	2		*CUSTOMER SUBSTATION			11
5	1					12
2	3	1				13
101	4					14
56	2		*CUSTOMER SUBSTATION			15
12	3		*CUSTOMER SUBSTATION			16
14	1		*CUSTOMER SUBSTATION			17
28	2					18
101	4					19
56	3					20
73	3					21
15	2					22
56	2					23
56	2	1				24
66	4					25
14	2					26
28	2					27
11	4					28
84	3					29
11	1		*CUSTOMER SUBSTATION			30
81	4					31
28	1		*CUSTOMER SUBSTATION			32
56	2		*CUSTOMER SUBSTATION			33
28	2					34
3	3	1				35
28	3	1				36
9	1		*CUSTOMER SUBSTATION			37
28	2					38
5	3	1				39
21	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) 04/14/2021	Year/Period of Report End of 2020/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)	
45	2					1
90	4					2
8	3	1				3
22	1		*CUSTOMER SUBSTATION			4
73	3					5
56	2					6
56	3					7
5	2					8
5	6					9
56	1					10
84	3					11
56	2					12
2	3	1				13
76	3					14
3	3	1				15
18	2					16
100	4					17
56	2		*CUSTOMER SUBSTATION			18
25	1					19
50	2					20
87	4					21
28	1		*CUSTOMER SUBSTATION			22
15	2					23
53	2					24
15	2					25
39	2		*CUSTOMER SUBSTATION			26
28	1		*CUSTOMER SUBSTATION			27
14	1					28
56	2					29
73	3					30
14	1		*CUSTOMER SUBSTATION			31
14	1		*CUSTOMER SUBSTATION			32
6	5	1				33
22	1		*CUSTOMER SUBSTATION			34
9	1		*CUSTOMER SUBSTATION			35
12	6					36
38	4					37
112	4					38
9	6	2				39
11	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	04/14/2021	End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
112	4					1
28	1					2
56	2		*CUSTOMER SUBSTATION			3
44	2					4
22	1		*CUSTOMER SUBSTATION			5
56	2					6
34	1		*CUSTOMER SUBSTATION			7
56	2					8
70	2					9
106	4					10
14	1		*CUSTOMER SUBSTATION			11
32	2					12
45	2					13
101	4					14
56	2					15
28	2					16
81	4					17
14	1					18
28	1		*CUSTOMER SUBSTATION			19
22	1		*CUSTOMER SUBSTATION			20
56	2					21
21	2					22
6	3	1				23
21	2					24
28	1		*CUSTOMER SUBSTATION			25
14	1		*CUSTOMER SUBSTATION			26
28	1		*CUSTOMER SUBSTATION			27
13	1		*CUSTOMER SUBSTATION			28
8	1		*CUSTOMER SUBSTATION			29
73	3					30
6	3					31
10	1					32
8	3					33
6	3					34
14	1		*CUSTOMER SUBSTATION			35
28	1					36
6	1					37
22	1		*CUSTOMER SUBSTATION			38
28	1					39
21	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	04/14/2021	End of 2020/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)	
56	2		*CUSTOMER SUBSTATION			1
56	2					2
84	4					3
14	1		*CUSTOMER SUBSTATION			4
27	3		*CUSTOMER SUBSTATION			5
50	2					6
9	3	1				7
14	1					8
20	1					9
19	3		*CUSTOMER SUBSTATION			10
95	4					11
112	4					12
11	1					13
25	3	1				14
11	2					15
101	4					16
112	4					17
95	4					18
56	2					19
22	2					20
50	4					21
11	1	1				22
102	4					23
6	3	1				24
22	1		*CUSTOMER SUBSTATION			25
99	6					26
12	6	1				27
96	5	1				28
56	2					29
25	2					30
112	2					31
112	4					32
104	4					33
11	1		*CUSTOMER SUBSTATION			34
50	2					35
112	4					36
56	2					37
38	6					38
28	1					39
5	3	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) 04/14/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
90	4					1
45	2		*CUSTOMER SUBSTATION			2
56	2		*CUSTOMER SUBSTATION			3
84	3					4
50	3					5
2	3		*CUSTOMER SUBSTATION			6
112	4		*CUSTOMER SUBSTATION			7
84	3		*CUSTOMER SUBSTATION			8
7	1		*CUSTOMER SUBSTATION			9
28	1		*CUSTOMER SUBSTATION			10
101	4					11
11	1					12
45	2		*CUSTOMER SUBSTATION			13
28	2					14
8	3					15
28	2					16
22	1					17
28	2					18
14	1					19
73	3					20
56	3					21
5	1					22
9	3	1	*CUSTOMER SUBSTATION			23
56	2					24
44	2					25
15	2					26
28	2					27
14	1		*CUSTOMER SUBSTATION			28
14	1		*CUSTOMER SUBSTATION			29
84	3					30
13	2					31
28	1		*CUSTOMER SUBSTATION			32
40	2		*CUSTOMER SUBSTATION			33
8	1		*CUSTOMER SUBSTATION			34
88	4					35
112	4					36
56	2		*CUSTOMER SUBSTATION			37
56	2					38
14	1		*CUSTOMER SUBSTATION			39
101	4					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	04/14/2021	End of 2020/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
68	3					2
28	2					3
56	2					4
84	4					5
6	3					6
56	2					7
11	2					8
28	2		*CUSTOMER SUBSTATION			9
106	3					10
21	2					11
10	1					12
10	1					13
56	3					14
112	4					15
28	2					16
45	2					17
112	4					18
11	1					19
56	2					20
56	2					21
56	2					22
7	1					23
56	2					24
112	4					25
14	1					26
28	1		*CUSTOMER SUBSTATION			27
6	1		*CUSTOMER SUBSTATION			28
170	8		*CUSTOMER SUBSTATION			29
6	3					30
22	1		*CUSTOMER SUBSTATION			31
56	2					32
14	1					33
101	4					34
10	2					35
56	3					36
25	2					37
101	4					38
11	1		*CUSTOMER SUBSTATION			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) 04/14/2021	Year/Period of Report End of 2020/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)	
56	2					1
14	1		*CUSTOMER SUBSTATION			2
101	4					3
56	2					4
6	3	1				5
76	3					6
112	4					7
11	1	1				8
7	1					9
17	1		*CUSTOMER SUBSTATION			10
28	2		*CUSTOMER SUBSTATION			11
70	3					12
13	2					13
106	4					14
112	4					15
50	2					16
45	2					17
56	2					18
56	2					19
5	1					20
84	4					21
25	2					22
5	3	1				23
56	2					24
56	2					25
56	2					26
3	1					27
56	3					28
9	1					29
45	2					30
14	1		*CUSTOMER SUBSTATION			31
56	2					32
56	2					33
28	1	1				34
14	1		*CUSTOMER SUBSTATION			35
3	3	1				36
14	1					37
13	1		*CUSTOMER SUBSTATION			38
28	2		*CUSTOMER SUBSTATION			39
45	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	04/14/2021	End of 2020/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)	
14	1		*CUSTOMER SUBSTATION			1
28	1		*CUSTOMER SUBSTATION			2
28	1					3
28	1	1				4
1	1					5
14	1		*CUSTOMER SUBSTATION			6
14	1					7
100	4					8
28	2					9
21	2					10
21	2					11
56	2					12
28	2					13
6	1	1				14
5	1					15
84	3					16
101	4					17
56	2					18
84	3					19
28	2					20
28	2					21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2021	End of 2020/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	See Allocation Process Footnotes			
3	Cash	Edison International	131	2,164
4	Other Accounts Receivable	Edison International	143	-647,038
5	Prepayments	Edison International	165	66,667,811
6	Misc. Current and Accrued Assets	Edison International	174	685,288
7	Miscellaneous Paid-In Capital	Edison International	211	-1,428,931,755
8	Accumulated Provision for Pension and Benefits	Edison International	228.3	1,405,093
9	Accounts Payable	Edison International	232	1,031,155
10	Taxes Accrued	Edison International	236	-50,398,215
11	Miscellaneous Current and Accrued Liabilities	Edison International	242	31,029
12	Donations	Edison International	426.1	21,775,675
13	Expenditures for Certain Civic, Pol. & Rel'd Activ	Edison International	426.4	6,330,995
14	Other Deductions	Edison International	426.5	2,681,368
15	Other Interest Expense	Edison International	431	453,977
16	Dividends Declared	Edison International	438	1,132,000,000
17	Adjustment to Retained Earnings	Edison International	439	-1,246,609
18	Other Expenses	Edison International	557	23,124
19	Miscellaneous Transmission Expenses	Edison International	566	8,824
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison International	131	-3,315,920
22	Other Accounts Receivable	Edison International	143	8,329
23	Accounts Receivable	Edison International	146	-61,989
24	Accounts Payable	Edison International	232	4,002,217
25	Taxes Accrued	Edison International	236	9
26	Miscellaneous Current and Accrued Liabilities	Edison International	242	-163,536
27	Taxes Other than Inc. Taxes, Utility Op. Income	Edison International	408.1	86,031
28	Expenditures for Certain Civic, Pol. & Relt'd Act	Edison International	426.4	4,205
29	Other Deductions	Edison International	426.5	11
30	Rent	Edison International	454	1,993,472
31	Other Electric Revenues	Edison International	456	77,916
32	Other Expenses	Edison International	557	1,033
33	Miscellaneous Distribution Expenses	Edison International	588	6,435
34	Administrative and General Salaries	Edison International	920	2,214,528
35	Outside Services Employed	Edison International	923	412,860
36	Injuries and Damages	Edison International	925	22,818
37	Employee Pension and Benefits	Edison International	926	2,373,116
38	Miscellaneous General Expenses	Edison International	930.2	5,952
39				
40			TOTAL	7,667,487
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Operation Supervision and Engineering	Edison International	580	14,200

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	04/14/2021	End of 2020/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Miscellaneous Distribution Expenses	Edison International	588	672,750
4	Customer Assistance Expenses	Edison International	908	88
5	Administrative and General Salaries	Edison International	920	1,465,287
6	Outside Services Employed	Edison International	923	17,119,919
7	Property Insurance	Edison International	924	-1,381,510
8	Injuries and Damages	Edison International	925	-953,128
9	Miscellaneous General Expenses	Edison International	930.2	4,908,402
10	Rent	Edison International	931	52,236
11				
12			TOTAL	-226,228,870
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison Mission Group	131	6,301
22	Accounts Payable	Edison Mission Group	232	80,958
23	Miscellaneous Current and Accrued Liabilities	Edison Mission Group	242	109
24	Taxes Other than Inc. Taxes, Utility Op. Income	Edison Mission Group	408.1	10,229
25	Rent	Edison Mission Group	454	67,499
26	Other Electric Revenues	Edison Mission Group	456	9,601
27	Admin. And Gen. Salaries/Office Supp. and Exp.	Edison Mission Group	920	376,708
28	Outside Services Employed	Edison Mission Group	923	29
29	Injuries and Damages	Edison Mission Group	925	1,547
30	Employee Pension and Benefits	Edison Mission Group	926	60,708
31	Miscellaneous General Expenses	Edison Mission Group	930.2	134
32				
33			TOTAL	613,823
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Prepayments	Edison Insurance Services	165	235,235,951
3	Accumulated Provision for Injuries and Damages	Edison Insurance Services	228.2	
4				

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	04/14/2021	End of 2020/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.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5			TOTAL	235,235,951
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison Energy Group	131	-233,710
22	Prepayments	Edison Energy Group	165	100
23	Accounts Payable	Edison Energy Group	232	202,447
24	Miscellaneous Current and Accrued Liabilities	Edison Energy Group	242	-17,090
25	Taxes Other Than Inc. Taxes, Utility Op. Income	Edison Energy Group	408.1	21,695
26	Other Deductions	Edison Energy Group	426.5	16
27	Rent	Edison Energy Group	454	142,773
28	Other Electric Revenues	Edison Energy Group	456	117,391
29	Admin. & Gen. Salaries	Edison Energy Group	920	420,453
30	Outside Services Employed	Edison Energy Group	923	17,181
31	Injuries and Damages	Edison Energy Group	925	3,287
32	Employee Pension and Benefits	Edison Energy Group	926	224,218
33	Miscellaneous General Expenses	Edison Energy Group	930.2	6,522
34				
35			TOTAL	905,283
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	04/14/2021	End of 2020/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.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7				
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				
35				
36				
37				
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39				
40				
41				
42				

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

Allocation Process Footnotes:

A. Directly Charged: All costs associated with goods or services are billed to/from the utility.
B. 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.
C. Equity Investment: This allocation method is based on the equity of each affiliate. Beginning in 2018, this allocation method is no longer in use.
D. Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.
E. Pre-determined fixed percentage: Allocation is based on amount of time spent on activities for SCE.

Schedule Page: 429 Line No.: 3 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 4 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 5 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 6 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 7 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 7 Column: d

The Board of Directors of Edison International approved two resolutions to give Southern California Edison ("SCE") $1.432 billion of capital contributions in 2020.

Schedule Page: 429 Line No.: 8 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 9 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 10 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 11 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 12 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 13 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 14 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 15 Column: a

Please refer to Column (a) Line 2 for allocation process: B

Schedule Page: 429 Line No.: 16 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 17 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 18 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 19 Column: a

Please refer to Column (a) Line 2 for allocation process: A

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

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 22 Column: a

Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 23 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 24 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 25 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 26 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 27 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 28 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 29 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 30 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 31 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 32 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 33 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429 Line No.: 34 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429 Line No.: 35 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429 Line No.: 36 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429 Line No.: 37 Column: a
Please refer to Column (a) Line 2 for allocation process: A, D

Schedule Page: 429 Line No.: 38 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.1 Line No.: 2 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 3 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 4 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 5 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D, E

Schedule Page: 429.1 Line No.: 6 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, E

Schedule Page: 429.1 Line No.: 7 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 8 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.1 Line No.: 9 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.1 Line No.: 10 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 21 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 22 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 23 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 24 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 25 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 26 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.1 Line No.: 27 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429.1 Line No.: 28 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429.1 Line No.: 29 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.1 Line No.: 30 Column: a
Please refer to Column (a) Line 2 for allocation process: A, D

Schedule Page: 429.1 Line No.: 31 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.2 Line No.: 2 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 3 Column: a
In 2018, SCE recorded $1 billion in expected recoveries from Edison Insurance Services, Inc. ("EIS"), a wholly-owned subsidiary of Edison International, for various wildfire liability insurance policies. EIS fully reinsured the exposure for these policies through the commercial reinsurance market. Of the $1 billion expected recoveries, SCE received payments of $535 million in 2020 and $197 million in 2019 from EIS, which were reflected in FERC account 228.2 Accumulated Provision for Injuries and Damages. At December 31, 2020, SCE had $268 million in expected recoveries remaining from two insurance policies.

Schedule Page: 429.2 Line No.: 21 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 22 Column: a
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Schedule Page: 429.2 Line No.: 23 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 24 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 25 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 26 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 27 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 28 Column: a
Please refer to Column (a) Line 2 for allocation process: A

Schedule Page: 429.2 Line No.: 29 Column: a
Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429.2 Line No.: 30 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B, D

Schedule Page: 429.2 Line No.: 31 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule Page: 429.2 Line No.: 32 Column: a

Please refer to Column (a) Line 2 for allocation process: A, D

Schedule Page: 429.2 Line No.: 33 Column: a

Please refer to Column (a) Line 2 for allocation process: A, B

Schedule	Page No.