

2020
ANNUAL REPORT

of

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000, B7C
San Francisco, CA 94177

to the

Public Utilities Commission
of the
State of California
For the Year Ended December 31, 2020



Volume No. 1 (Form 1)

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Pacific Gas and Electric Company

We have audited the accompanying financial statements of Pacific Gas and Electric Company (the "Company"), which comprise the balance sheet – regulatory basis as of December 31, 2020, the related statements of income – regulatory basis, retained earnings – regulatory basis, and cash flows – regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Pacific Gas & Electric Company as of December 31, 2020, and the results of its operations and its cash flows for the year then ended in

accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting


As discussed in the introduction to Note 1 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Emphasis of Matter Regarding Emergence from Chapter 11

As discussed in Note 2 to the financial statements, the Utility emerged from Chapter 11 on July 1, 2020. Under the plan of reorganization, the Utility is required to comply with certain terms and conditions as described in Note 2 to the financial statements. Our opinion is not modified with respect to this matter.

Restricted Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

A handwritten signature in black ink that reads "Deloitte + Touche LLP". The signature is written in a cursive, flowing style.

April 13, 2021

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

IDENTIFICATION		
01 Exact Legal Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	02 Year/Period of Report End of <u>2020/Q4</u>	
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) 77 BEALE STREET, P.O BOX 770000, SAN FRANCISCO, CA 94177		
05 Name of Contact Person JENNIFER GARBODEN	06 Title of Contact Person DIRECTOR, CORP ACCOUNTING	
07 Address of Contact Person (Street, City, State, Zip Code) 77 BEALE STREET, MAIL CODE B7A, P.O BOX 770000, SAN FRANCISCO, CA 94177		
08 Telephone of Contact Person, Including Area Code (415) 973-5456	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/13/2021

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 DAVID THOMASON	03 Signature  DAVID THOMASON	04 Date Signed (Mo, Da, Yr) 04/13/2021
02 Title VP, CONTROLLER, UTILITY CFO		

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
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12	Notes to Financial Statements	122-123	
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15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NONE
18	Electric Plant Held for Future Use	214	NONE
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NONE
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
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32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	NONE
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	NONE
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	NONE
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

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 PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report End of <u>2020/Q4</u>
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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.

David S. Thomason, Vice President, Controller and CFO
77 Beale Street, B11H
San Francisco, Ca 94105

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, October 1905

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

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

Electricity and natural gas distribution, electric generation, procurement, and transmission, and natural gas procurement, transportation, and storage.

State of California only.

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) No

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 04/13/2021	Year/Period of Report End of <u>2020/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Effective January 1, 1997, PG&E Corporation became the holding company of Pacific Gas and Electric Company.

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	Eureka Energy Company	Formerly managed	100	
2		the Utility's Utah coal		
3		venture. Currently holds		
4		part of the Marre Ranch		
5		property in San Luis		
6		Obispo County.		
7				
8	Midway Power, LLC	Formed to be the ownership	100	
9		entity for real estate and		
10		licenses for a suspended		
11		development project.		
12				
13	Natural Gas Corporation of California (NGC)	Entity used to amortize	100	
14		remaining Gas		
15		Exploration and		
16		Development Account		
17		assets.		
18				
19	FuelCo LLC	Formed to share costs and	50	1
20		reduce fuel acquisition		
21		costs.		
22				
23	Pacific Energy Fuels Company	Formed to own and	100	
24		finance the nuclear fuel		
25		inventory previously owned		
26		by Pacific Energy Trust		
27				

CORPORATIONS CONTROLLED BY RESPONDENT

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Standard Pacific Gas Line Incorporated	Engaged in the transportation	85.71	
3		of natural gas in California.		
4		The Utility owns an 85.71%		
5		interest and Chevron Pipe		
6		Line Company owns the		
7		remaining 14.29% interest.		
8				
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11				
12	Morro Bay Mutual Water Company	Formed to jointly hold	50	2
13		property rights in connection		
14		with the divestiture of the		
15		Morro Bay Power Plant.		
16				
17	Moss Landing Mutual Water Company	Formed to jointly hold	33	3
18		propert rights in connection		
19		with the divestiture of the		
20		Moss Landing Power Plant.		
21				
22	Alaska Gas Exploration Associates	Formed to explore,	50	4
23		develop, produce, acquire,		
24		and market oil and gas		
25		reserves in Alaska.		
26				
27				

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.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	STARS Alliance, LLC	Formed to increase efficiency	25	5
2		and reduce costs related to		
3		the operation of the members		
4		nuclear generation		
5		facilities.		
6				
7	PG&E AR Facility, LLC	Formed for potential accounts	100	
8		receivable securitization		
9		transactions		
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

Members include: Union Electric Company d/b/a AmerenMO. 12/8/17 - Certificate of Withdrawal filed with the state of Texas.

Schedule Page: 103.1 Line No.: 12 Column: d

Members include: Dynergy Moss Landing. Pacific Gas and Electric Company is one of 2 members of the non-profit mutual benefit corporation.

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

Members include: Dynergy Moss Landing and Moon Glow Dairy. Pacific Gas and Electric Company is one of 3 members of the non-profit mutual benefit corporation.

Schedule Page: 103.1 Line No.: 22 Column: d

Currently inactive.

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

Members include: Arizona Public Service Company, Union Electric Company, d/b/a AmerenMO, and Wolf Creek Nuclear Operating Corporation. Pacific Gas and Electric Company has a 1/4 equity interest.

Waiting for confirmation of withdrawal from Texas.

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	Interim President, Pacific Gas and Electric Company	Michael A. Lewis	951,933
2	Senior Vice President, Generation and Chief Nuclear	James M. Welsch	572,250
3	Officer, Pacific Gas and Electric Company		
4	Vice President, Chief Financial Officer and Controller, Pacific Gas and Electric Company	David S. Thomason	339,479
5			
6	Chief Executive Officer and President, Pacific Gas and Electric Company	Andrew M. Vesey	587,310
7			
8	Senior Vice President and General Counsel, Pacific Gas and Electric Company	Janet C. Loduca	380,096
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FOOTNOTE DATA			

Schedule Page: 104 Line No.: 1 Column: b

Mr. Lewis, formerly Senior Vice President, Electric Operations, became Interim President on August 1, 2020. Mr. Lewis' employment ended January 1, 2021.

Schedule Page: 104 Line No.: 6 Column: b

Mr. Vesey's employment ended August 4, 2020.

Schedule Page: 104 Line No.: 8 Column: b

Ms. Loduca's employment ended August 16, 2020.

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	Rajat Bahri	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Richard R. Barrera	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Jeffrey L. Bleich	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Nora Mead Brownell	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
16		
17	Cheryl F. Campbell	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21	Kerry W. Cooper	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
24		
25	Jessica L. Denecour	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
28		
29	Mark E. Ferguson, III	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Robert C. Flexon	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37	Fred J. Fowler	c/o PG&E Corporation
38		77 Beale Street, 32nd Floor
39		San Francisco, CA 94105
40		
41	W. Craig Fugate	c/o PG&E Corporation
42		77 Beale Street, 32nd Floor
43		San Francisco, CA 94105
44		
45	Arno L. Harris	c/o PG&E Corporation
46		77 Beale Street, 32nd Floor
47		San Francisco, CA 94105
48		

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	William D. Johnson	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Michael J. Leffell	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	Michael A. Lewis	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
12		
13	Dominique Mielle	c/o PG&E Corporation
14		77 Beale Street, 32nd Floor
15		San Francisco, CA 94105
16		
17	Meridee A. Moore	c/o PG&E Corporation
18		77 Beale Street, 32nd Floor
19		San Francisco, CA 94105
20		
21	Eric D. Mullins	c/o PG&E Corporation
22		77 Beale Street, 32nd Floor
23		San Francisco, CA 94105
24		
25	Michael R. Niggli	c/o PG&E Corporation
26		77 Beale Street, 32nd Floor
27		San Francisco, CA 94105
28		
29	Kristine M. Schmidt	c/o PG&E Corporation
30		77 Beale Street, 32nd Floor
31		San Francisco, CA 94105
32		
33	Dean L. Seavers	c/o PG&E Corporation
34		77 Beale Street, 32nd Floor
35		San Francisco, CA 94105
36		
37	William L. Smith	c/o PG&E Corporation
38		77 Beale Street, 32nd Floor
39		San Francisco, CA 94105
40		
41	Oluwadara (Dara) J. Treseder	c/o PG&E Corporation
42		77 Beale Street, 32nd Floor
43		San Francisco, CA 94105
44		
45	Andrew M. Vesey, Chief Executive Officer and President,	c/o PG&E Corporation
46	Pacific Gas and Electric Company ***	77 Beale Street, 32nd Floor
47		San Francisco, CA 94105
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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	Benjamin F. Wilson	c/o PG&E Corporation
2		77 Beale Street, 32nd Floor
3		San Francisco, CA 94105
4		
5	Alejandro D. Wolff	c/o PG&E Corporation
6		77 Beale Street, 32nd Floor
7		San Francisco, CA 94105
8		
9	John M. Woolard	c/o PG&E Corporation
10		77 Beale Street, 32nd Floor
11		San Francisco, CA 94105
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 5 Column: a Richard R. Barrera resigned on 7/1/2020.
Schedule Page: 105 Line No.: 9 Column: a Jeffrey L. Bleich resigned on 5/1/2020.
Schedule Page: 105 Line No.: 13 Column: a Nora Mead Brownell resigned on 7/1/2020.
Schedule Page: 105 Line No.: 37 Column: a Fred J. Fowler resigned on 7/1/2020.
Schedule Page: 105.1 Line No.: 1 Column: a William D. Johnson resigned on 6/30/2020.
Schedule Page: 105.1 Line No.: 5 Column: a Michael J. Leffell resigned on 7/1/2020.
Schedule Page: 105.1 Line No.: 9 Column: a Michael A. Lewis resigned on 12/31/2020.
Schedule Page: 105.1 Line No.: 13 Column: a Dominique Mielle resigned on 6/30/2020.
Schedule Page: 105.1 Line No.: 17 Column: a Meridee A. Moore resigned on 7/1/2020.
Schedule Page: 105.1 Line No.: 21 Column: a Eric D. Mullins resigned on 7/1/2020.
Schedule Page: 105.1 Line No.: 29 Column: a Kristine M. Schmidt resigned on 7/1/2020.
Schedule Page: 105.1 Line No.: 45 Column: a Andrew M. Vesey resigned on 8/3/2020.
Schedule Page: 105.2 Line No.: 5 Column: a Alejandro D. Wolff resigned on 7/1/2020.

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

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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	PG&E FERC Electric Tariff Volume No. 5	ER19-13-000
2	PG&E FERC Electric Tariff Volume No. 4	ER20-2878-000
3		
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Name of Respondent
PACIFIC GAS AND ELECTRIC COMPANY

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/13/2021

Year/Period of Report
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)?

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	20201201-5280	12/01/2020	ER19-13-000	Annual Formula Transmission Rate	PG&E FERC Electric Tariff Volume No.
2	20201201-5280	12/01/2020	ER19-1816-000	Annual Formula Transmission Rate	PG&E FERC Electric Tariff Volume No.
3	20201201-5280	12/01/2020	ER20-2265-000	Annual Formula Transmission Rate	PG&E FERC Electric Tariff Volume No.
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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		NOT APPLICABLE		
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/13/2021	Year/Period of Report End of <u>2020/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

PACIFIC GAS AND ELECTRIC COMPANYs
IMPORTANT CHANGES DURING THE YEAR

For the Year Ended December 31, 2020

1. **Changes in and important additions to franchise rights:**

PG&E has received a request from the City of Richmond proposing a change in the franchise fee rate for the electric and gas franchises with the City. The parties have been unable to informally resolve the matter and it has been referred to arbitration to address whether the City has met the conditions set forth in the franchise agreements for requesting a change to the franchise fee rate, and if so, what would be the appropriate change in the franchise fee rate.

2. **Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies:**

None.

3. **Purchase or sale of an operating unit or system:**

Sale:

None.

Purchase:

None.

4. **Important leaseholds that have been acquired or given, assigned or surrendered:**

On June 5, 2020, the Utility entered into an Agreement to Enter Into Lease and Purchase Option (the "Agreement") with TMG Bay Area Investments II, LLC ("TMG"). The Agreement provides that, contingent on (i) entry of an order by the Bankruptcy Court authorizing the Utility to enter into the Agreement and the Lease Agreement (as defined below), subject to certain conditions, and (ii) acquisition of the Lakeside Building by BA2 300 Lakeside LLC ("Landlord"), a wholly owned subsidiary of TMG, the Utility and Landlord will enter into an office lease agreement (the "Lease Agreement") for approximately 910,000 rentable square feet of space within the building located at the Lakeside Building to serve as the Utility's principal administrative headquarters (the "Lease"). On June 9, 2020, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court authorizing them to enter into the Agreement and grant related relief. The Bankruptcy Court entered an order approving the motion on June 24, 2020.

Pursuant to the terms of the Agreement, concurrent with the Landlord's acquisition of the Lakeside Building, on October 23, 2020, the Utility and the Landlord entered into the Lease, and the Utility issued to Landlord (i) an option payment letter of credit in the amount of \$75 million, and (ii) a lease security letter of credit in the amount of \$75 million.

The term of the Lease will begin on or about March 1, 2022. The Lease term will expire 34 years and 11 months after the commencement date, unless earlier terminated in accordance with the terms of the Lease. In addition to base rent, the Utility will be responsible for certain costs and charges specified in the Lease, including

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

insurance costs, maintenance costs and taxes.

The Lease requires the Landlord to pursue approvals to subdivide the real estate it owns surrounding the Lakeside Building to create a separate legal parcel that contains the Lakeside Building (the "Property") that can be sold to the Utility. The Lease grants to the Utility an option to purchase the Property, following such subdivision, at a price of \$892 million, subject to certain adjustments (the "Purchase Price"). The Purchase Price would not be paid until 2023.

In connection with entry into the Agreement, the Utility intends to sell its current office space generally located at 77 Beale Street, 215 Market Street, 245 Market Street and 50 Main Street, San Francisco, California 94105, and associated properties owned by the Utility ("SFGO"). Any sale of the SFGO would be subject to approval by the CPUC. On September 30, 2020, the Utility filed an application with the CPUC seeking authorization to sell the SFGO.

At December 31, 2020, the Agreement had no impact on the Utility's Condensed Consolidated Financial Statements.

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

Electric:

On April 20, 2020, the Gates 500/230 kV Transformer No. 2 Installation Project was released to operations. This project, located in Fresno County, added a second 500/230 kV Transformer at the Gates 500/230/70 kV Substation. This project was built to provide full deliverability to renewable generation in the Fresno area and additional flexibility for pumping operations at Helms Pumped Storage Plant.

On October 8, 2020, the Delevan 230 kV Shunt Reactor Project was released to operations. This project, located in Colusa County, installed three steps for a total of 202 MVar shunt reactors at Delevan 230kV Substation to help control system voltages.

Gas:

None.

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 maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee:

a) Financings:

As part of its emergence from bankruptcy, PG&E issued \$8.925 billion in First Mortgage Bonds on June 16, 2020. The proceeds from this issuance were used to pay off claims related to PG&E's filing for Ch. 11 bankruptcy in 2019.

On July 1, 2020, the Utility issued \$11.9 billion of its first mortgage bonds in satisfaction of certain of its pre-petition senior unsecured debt.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

On July 1, 2020, the Utility reinstated \$9.6 billion aggregate principal amount of the Utility Senior Notes. Each series of the Utility Reinstated Senior Notes was collateralized by the Utility's delivery of a first mortgage bond in a corresponding principal amount to the applicable trustee for the benefit of the holders of the Utility Reinstated Senior Notes.

On November 16, 2020, the Utility completed the sale of \$1.45 billion aggregate principal amount of floating rate first mortgage bonds due November 15, 2021. Proceeds from the sale of the mortgage bonds were used for general corporate purposes, including the repayment of borrowings outstanding under the Receivables Securitization Program and borrowings outstanding under the Utility Revolving Credit Facility.

b) Bank Credit Facilities:

On January 29, 2020, PG&E drew the \$500 million delayed draw term loan available through the Debtor-In-Possession (DIP Facility).

On July 1, 2020, the Debtor-In-Possession facilities were repaid in full and all commitments thereunder were terminated in connection with emergence from Chapter 11.

On July 1, 2020, the Utility entered into a \$3.5 billion revolving credit agreement with JPM, and Citibank, N.A. as co-administrative agents, and Citibank, N.A., as designated agent. The Utility Revolving Credit Agreement has a maturity date of three years after July 1, 2020, subject to two one-year extensions at the option of the Utility. The Utility Revolving Credit Facility has a maximum letter of credit sublimit equal to \$1.5 billion. As of December 31, 2020, the Utility had outstanding borrowings of \$605 million and \$1.0 billion of letters of credit outstanding under this credit facility.

On July 1, 2020, the Utility obtained a \$3.0 billion secured term loan under a term loan credit agreement with JPM, as administrative agent. The credit facilities under the Utility Term Loan Credit Facility consist of a \$1.5 billion 364-day term loan facility and a \$1.5 billion 18-month term loan facility. The maturity date for the 364-day term loan facility is June 30, 2021 and the maturity date for the Utility 18-month term loan facility is January 1, 2022. As of December 31, 2020, the Utility had outstanding borrowings of \$3.0 billion under this term loan facility.

Non-bankruptcy short-term borrowings are authorized by CPUC Decision No. 09-05-002.

Bankruptcy short-term borrowings were authorized by CPUC Decision No. 19-01-025.

c) Surety Bonds and Financial Guarantees Backed by Insurance:

From January 1, 2020 to December 31, 2020 \$79,784,735 in surety bond obligations were issued in conformance with the CPUC Decision No. 12-04-015. As of December 31, 2020, there was a total of \$210,966,744.81 of surety bond obligations

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

outstanding.

d) Capital Support:

CPUC Decision No. 91-12-057 (as modified by Decision No. 99-04-068) authorized the Utility to provide capital support to regulated and unregulated subsidiaries. At December 31, 2020, the Utility has no outstanding future capital commitments to unregulated subsidiaries and affiliates.

e) Preferred stock repayments:

None.

7. Changes in articles of incorporation or amendments to charter. Explain the nature and purpose of such changes or amendments:

On June 22, 2020, the Utility's Articles of Incorporation were amended and restated in connection with confirmation of the Utility's Plan of Reorganization to:

- prohibit the issuance of any non-voting equity securities to the extent prohibited by section 1123(a)(6) of the Bankruptcy Code; and
- establish ownership and transfer restrictions with respect to equity securities of the Utility in order to reduce the possibility of an equity ownership shift that could result in limitations on the Utility's ability to utilize net operating loss carryforwards and other tax attributes from prior taxable years for federal income tax purposes
- incorporate into the Articles the terms of the authorized Series of Preferred Stock and delete unnecessary references to Certificates of Determination for such Series.

8. State the estimated annual effect and nature of any important wage scale changes during the period:

As provided for in labor agreements with the International Brotherhood of Electrical Workers ("IBEW"), Local 1245, representing a majority of the Utility's employees in physical and clerical classifications; the Engineers and Scientists of California, ("ESC"), representing certain Utility employees in the technical and engineering classifications; and the Service Employees International Union ("SEIU"), representing certain Utility security officers at Diablo Canyon Nuclear Power Plant, the following general wage increases were granted effective January 1, 2020:

IBEW Clerical classifications	3.00%
IBEW Physical classifications	3.00%
ESC non-exempt and some exempt classifications	3.00%
ESC other exempt classifications	3.00%
SEIU classifications	3.00%

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PACIFIC GAS AND ELECTRIC COMPANY			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

The full annual cost of the above general wage increase is approximately \$46,994,205.

9. State briefly the status of any materially important legal proceedings pending at the end of the period and the results of any such proceedings culminated during the period:

Refer to Part I, Item 1A. Risk Factors, Part II, Item 7. MD&A "Enforcement and Litigation Matters" and Notes 2, 14, and 15 of the Notes to the Consolidated Financial Statements in Item 8 of PG&E Corporation's and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2020. Four copies of the Form 10-K report are filed in accordance with Instruction III(c) of Instructions For Filing the FERC Form No. 1.

10. Describe briefly any materially important transactions of the not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, 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:

"Five Percent Owners"

During 2020, multiple beneficial owners of at least 5 percent of PG&E Corporation common stock provided services to PG&E Corporation, Pacific Gas and Electric Company ("Utility"), and related entities. These entities were identified based solely on a review of Schedule 13Gs (or any amendments) filed with the Securities and Exchange Commission as of the date of this report. Consistent with SEC rules, if a beneficial owner's holdings fell below 5 percent during the year, the descriptions only discuss transactions until the party was no longer a 5 percent owner.

- The Vanguard Group ("Vanguard") provided asset management services to the trusts securing benefits in the event of a change in control, and The PG&E Corporation Foundation. In each of these cases, the services are subject to terms comparable to those that could be obtained in arm's-length dealings with an unrelated third party. PG&E Corporation and the Utility expect that these entities will continue to provide similar services and products in the future, in the normal course of business operations.

The value of payments to Vanguard for the period January 2020 through March 2021 was below the \$120,000 disclosure threshold set forth in SEC Reg. S-K, Item 404(a).

- Gallagher Financial Advisory Services ("Gallagher") provided independent fiduciary services to the PG&E Corporation Stock Fund in the 401(k) Plan, and, solely by reason of that fact, is deemed to beneficially own the fund's shares (and thereby is deemed a five percent owner of PG&E Corporation common stock). Gallagher was selected from among five different candidates to provide these services, and any provider similarly would have become a five percent owner if selected as the independent fiduciary. The terms of the engagement are consistent with those obtainable in arm's-length negotiations.

NOTE: Following PG&E Corporation's and the Utility's emergence from Chapter 11 and related changes to ownership of PG&E Corporation common stock,

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Gallagher no longer is a 5% owner.

- Affiliates of Fidelity Management and Research Company LLC (FMC) provide recordkeeper and trustee services for compensation and benefit plans sponsored by PG&E Corporation and the Utility. The terms of the engagements are comparable to those that could be obtained in arm's-length dealings with an unrelated third party. PG&E Corporation and the Utility expect that these entities will continue to provide similar services and products in the future, in the normal course of business operations.

The value of payments to FMC affiliates during 2020 was approximately \$860,000, which exceeds the \$120,000 disclosure threshold set forth in SEC Reg S-K Item 404.

- Fire Victim Trust (the "Trust") - In connection with the Plan of Reorganization, in July and August 2020, the Utility distributed 477,743,590 shares of PG&E Corporation common stock to the Trust and entered into the following agreements with the Trust:
 - Assignment Agreement: On July 1, 2020, the Utility and the Trust entered into an assignment agreement (the "Assignment Agreement"). Pursuant to the Assignment Agreement, the Utility funded the Trust with aggregate consideration consisting of \$6.75 billion in cash (including \$1.35 billion on a deferred basis in accordance with the Tax Benefits Payment Agreement described below) and 476,995,175 shares of PG&E Corporation common stock (the "Initial Plan Shares"). On August 3, 2020, pursuant to an antidilution provision in the Assignment Agreement, the Utility distributed an additional 748,415 shares of PG&E Corporation common stock to the Trust (together with the Initial Plan Shares, the "Plan Shares").
 - Registration Rights Agreement: In addition to various obligations relating to registration of the Common Stock (summarized in PG&E Corporation's Current Report on Form 8-K filed on June 24, 2020), PG&E Corporation is required to pay the fees and expenses for one counsel for the Trust (subject to a cap of \$100,000 for the initial registration and for each assisted underwritten offering) in connection with the initial registration and each assisted underwritten offering, but excluding any underwriting discounts or commissions or fees and expenses of the Trust.
 - Tax Benefits Payment Agreement: The Utility agreed to pay to the Trust in cash an aggregate amount of \$1.35 billion, comprising (i) at least \$650 million of tax benefits for fiscal year 2020 to be paid on or before January 15, 2021 (the "First Payment Date"), and (ii) of the remainder of the \$1.35 billion of tax benefits for fiscal year 2021 to be paid on or before January 15, 2022. On January 15, 2021, the Utility paid the first tranche of tax benefits of approximately \$758 million pursuant to the Tax Benefits Agreement.

During the first quarter of 2020, one group of beneficial owners of at least 5% of PG&E Corporation common stock (Knighthead Capital Management (Knighthead) and Abrams

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Capital Management (Abrams), together), and one owner of at least 5% of Pacific Gas and Electric Company First Preferred Stock (Stonehill Capital Partners (Stonehill)) entered into amendments to previously executed backstop commitment letters with PG&E Corporation. The backstop commitment letters, as amended, were entered into in connection with the companies' Plan of Reorganization, and generally provide that these related parties committed to fund the companies in consideration of the issuance of new shares of PG&E Corporation common stock.

As of the second quarter of 2020, backstop commitment letters had been entered with one owner of at least 5% of Pacific Gas and Electric Company First Preferred Stock (Stonehill Capital Partners). There were no changes to these backstop commitment letters during the remainder of 2020. The backstop commitment letters terminated upon emergence from Chapter 11.

NOTE: Backstop commitment letters also had been entered into with one group of beneficial owners of at least 5% of PG&E Corporation common stock (Knighthead Capital Management (Knighthead) and Abrams Capital Management (Abrams), ("Knighthead and Abrams" together). However, Knighthead and Abrams ceased to be 5% shareholders during Q1 2020.

"Immediate Family Members"

Kathy Thomason is employed by the Utility as a Strategic Analyst, Principal. She is the wife of David Thomason, who is Vice President, Chief Financial Officer, and Controller of the Utility and an executive officer of the Utility. Ms. Thomason is, therefore, an "immediate family member" for purposes of SEC related person transaction disclosure rules. While Ms. Thomason is employed with the Utility, she will receive salary, short-term incentive awards, and other cash compensation and benefits, including increases in compensation, consistent with the Utility's standard compensation practices and policies.

We expect that the value of payments to Ms. Thomason for the period January 2020 through March 2021 (assuming she remains employed with the Utility during that period) will exceed the \$120,000 disclosure threshold set forth in SEC Reg S-K. Item 404(a), and intend to disclose that the value of annual transactions is approximately \$170,000.

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 to 1 to 11 above, such notes may be included on this page.

Not applicable.

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:

Directors

The following individuals were elected as Directors of the Utility:

- Rajat Behri
- Kerry W. Cooper

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PACIFIC GAS AND ELECTRIC COMPANY		04/13/2021	2020/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

- Jessica L. Dencour
- Mark E. Ferguson, III
- Robert C. Flexon
- W. Craig Fugate
- Arno L. Harris
- Michael A. Lewis
- Michael R. Niggli
- Dean L. Seavers
- Oluwadara (Dara) Treseder
- Benjamin F. Wilson

The following individuals are no longer Directors of the Utility:

- Richard R. Barrera
- Jeffrey L. Bleich
- Nora Mead Brownell
- Fred J. Fowler
- William D. Johnson
- Michael J. Leffell
- Michael A. Lewis
- Dominique Mielle
- Meridee A. Moore
- Eric D. Mullins
- Kristine M. Schmidt
- Andrew M. Vesey
- Alejandro D. Wolff

Officers

The following individuals became officers of the Utility:

- Dean L. Seavers, Chair of the Board
- Francisco Benavides, Vice President and Chief Safety Officer
- Sumeet Singh, Senior Vice President and Chief Risk Officer
- Aaron A. August, Vice President, Business Development & Customer Engagement
- Vincent M. Davis, Vice President, Customer Experience Operations
- David E. Hatton, Vice President, Human Resources Solutions
- William V. Manheim, Vice President, Deputy General Counsel, Operations
- Jan A. Nimick, Vice President, Power Generation
- Mark R. Seveska, Vice President, IT Products & Enterprise Platforms
- Alejandro (Alex) Vallejo, Vice President, Compliance & Ethics, and Deputy General Counsel
- Stephanie Williams, Vice President, Business Finance and Planning
- Brian M. Wong, Vice President, Deputy General Counsel, and Corporate Secretary
- Maureen R. Zawalick, Vice President, Generation Business & Technical Services
- Chris Zenner, Vice President, Residential Services & Digital Channels
- Lisa J. Crawford, Assistant Corporate Secretary
- Sujata Pagedar, Assistant Corporate Secretary

The following individuals' titles changed:

- Michael A. Lewis, Interim President (formerly Senior Vice President, Electric Operations)
- Francisco Benavides, Senior Vice President and Chief Safety Officer (formerly Vice

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

President and Chief Safety Officer)

- Stephen J. Cairns, Vice President and Chief Audit Officer (formerly Vice President, Internal Audit and Chief Risk Officer)
- Linda Y.H. Cheng, Vice President (formerly Vice President, Corporate Governance and Corporate Secretary)
- Aaron J. Johnson, Vice President, Wildfire Safety and Public Engagement (formerly Vice President, Customer Energy Solutions)
- Mary K. King, Vice President Talent and Chief Diversity Officer (formerly Vice President, Human Resources and Chief Diversity Officer)
- Deborah W. Powell, Vice President, Asset, Risk Management and Community Wildfire Safety Program (formerly Vice President, Power Generation)
- Brian M. Wong, Vice President, General Counsel, and Corporate Secretary (formerly Vice President, Deputy General Counsel, and Corporate Secretary)
- Margaret (Mari) K. Becker, Treasurer (formerly Assistant Treasurer)

The following individuals are no longer officers of the Utility:

- Jeffrey L. Bleich, Chair of the Board
- Michael A. Lewis, Interim President
- Andrew M. Vesey, Chief Executive Officer and President
- Julie M. Kane, Senior Vice President, Chief Ethics and Compliance officer, and Deputy General Counsel
- Kathleen B. Kay, Senior Vice President and Chief Information Officer
- Janet C. Loduca, Senior Vice President and General Counsel
- Dinyar B. Mistry, Senior Vice President, Human Resources
- Nicholas M. Bijur, Vice President and Treasurer
- Linda Y.H. Cheng, Vice President
- Thomas M. French, Vice President, Electric Transmission Operations
- Roy M. Kuga, Vice President, Energy Policy and Procurement Bankruptcy Strategy
- Rolando I. Trevino, Vice President, Gas Engineering and Design
- Wendy S. Lee, Assistant Corporate Secretary
- Eric A. Montizambert, Assistant Corporate Secretary

Major Security Holders

Changes to the major holders of the Utility's First Preferred Stock are as follows:

- Cede & Co., C/O DTCC-Transfer Operation Dept., 570 Washington Blvd Floor 1, Jersey City, NJ 08857, increased its share ownership from 9,710,090 shares as of December 31, 2019 to 9,738,824 shares as of December 31, 2020. (Approximately 94 percent of the total preferred shares outstanding).
- Rinehart C. Heinitz 3680 Camanche Parkway N, Ione, CA 95640-9464 became a major holder with 6,540 shares.
- Josephine S. Allen TR UDT Dec 4 91, 118 Scenic Dr, Orinda, CA 94563-3414 is no longer a major holder.

Dividend Payments

Refer to Note 6, Equity, of the Notes to Financial Statements on page 122-123 of the FERC Form 1.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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:

Not applicable.

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	99,319,294,639	93,917,917,269
3	Construction Work in Progress (107)	200-201	2,758,242,099	2,672,175,058
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		102,077,536,738	96,590,092,327
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	41,313,895,992	39,506,642,610
6	Net Utility Plant (Enter Total of line 4 less 5)		60,763,640,746	57,083,449,717
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	178,852,456	134,676,856
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		359,475,767	397,424,984
10	Spent Nuclear Fuel (120.4)		2,681,225,483	2,566,969,545
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,853,008,174	2,743,468,286
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		366,545,532	355,603,099
14	Net Utility Plant (Enter Total of lines 6 and 13)		61,130,186,278	57,439,052,816
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		55,907,325	55,907,325
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		30,315,734	29,974,881
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	134,313,797	48,216,341
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	104,757,860	361,842,950
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)		3,577,735,621	3,212,389,977
29	Special Funds (Non Major Only) (129)		1,153,128,788	879,638,841
30	Long-Term Portion of Derivative Assets (175)		135,917,617	123,756,001
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		5,136,169,417	4,655,818,991
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		59,291,720	294,434,921
36	Special Deposits (132-134)		143,144,862	7,195,190
37	Working Fund (135)		18,975	147,415
38	Temporary Cash Investments (136)		196,000,000	824,500,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		341,025,012	1,391,312,162
41	Other Accounts Receivable (143)		1,624,531,567	3,075,983,285
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		27,986,632	58,239,935
43	Notes Receivable from Associated Companies (145)		1,504,095,027	0
44	Accounts Receivable from Assoc. Companies (146)		46,819,315	62,212,613
45	Fuel Stock (151)	227	1,378,183	961,981
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	533,278,843	549,615,749
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	512,269,640	409,110,109

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		104,757,860	361,842,950
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		93,819,226	95,650,896
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		698,753,381	410,148,517
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		3,420	1,560,329
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		123,798,662	968,707,535
62	Miscellaneous Current and Accrued Assets (174)		613,965,320	185,743,895
63	Derivative Instrument Assets (175)		167,726,528	153,330,724
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		135,917,617	123,756,001
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)		6,391,257,572	7,886,776,435
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		198,238,360	693,998
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	51,795,210	68,590,956
72	Other Regulatory Assets (182.3)	232	16,056,902,402	7,027,240,817
73	Prelim. Survey and Investigation Charges (Electric) (183)		-558	-558
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)		3,056,319	1,358,396
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	5,832,130,624	45,196,485
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)		62,997,566	77,021,591
82	Accumulated Deferred Income Taxes (190)	234	9,318,986,643	9,503,725,902
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		31,524,106,566	16,723,827,587
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		104,237,627,158	86,761,383,154

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 04/13/2021	Year/Period of Report end of 2020/Q4
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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	1,321,874,045	1,321,874,045
3	Preferred Stock Issued (204)	250-251	257,994,575	257,994,575
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		1,805,194,230	1,805,194,230
7	Other Paid-In Capital (208-211)	253	26,516,580,090	6,780,547,928
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	6,916,899	6,916,899
10	(Less) Capital Stock Expense (214)	254b	28,951,886	28,951,886
11	Retained Earnings (215, 215.1, 216)	118-119	-4,351,842,483	-4,735,473,388
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-32,541,627	-59,869,210
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)	-4,621,218	1,017,789
16	Total Proprietary Capital (lines 2 through 15)		25,476,768,827	5,335,417,184
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	31,852,940,000	19,887,100,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		20,595,301	0
24	Total Long-Term Debt (lines 18 through 23)		31,832,344,699	19,887,100,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,211,735,102	1,732,629,877
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,769,431,843	26,007,532,982
29	Accumulated Provision for Pensions and Benefits (228.3)		2,342,629,053	1,914,041,383
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,338,475,830	1,530,158,186
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		194,661,444	124,040,367
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		6,412,100,889	5,853,792,194
35	Total Other Noncurrent Liabilities (lines 26 through 34)		14,269,034,161	37,162,194,989
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		3,555,000,000	3,138,570,758
38	Accounts Payable (232)		3,185,186,054	3,902,787,143
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		46,554,806	118,946,829
41	Customer Deposits (235)		113,023,366	180,930,636
42	Taxes Accrued (236)	262-263	453,585,015	466,656,094
43	Interest Accrued (237)		451,126,305	967,014,530
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		36,799,544	30,322,243
48	Miscellaneous Current and Accrued Liabilities (242)		1,378,666,788	768,630,901
49	Obligations Under Capital Leases-Current (243)		531,682,197	555,099,542
50	Derivative Instrument Liabilities (244)		217,016,272	146,893,267
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		194,661,444	124,040,367
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)		9,773,978,903	10,151,811,576
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		326,181,304	355,228,141
57	Accumulated Deferred Investment Tax Credits (255)	266-267	95,893,290	102,885,102
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,573,140,970	242,148,049
60	Other Regulatory Liabilities (254)	278	9,886,546,578	3,411,145,909
61	Unamortized Gain on Reaquired Debt (257)		429,928	572,251
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		8,980,592,464	8,462,844,659
64	Accum. Deferred Income Taxes-Other (283)		2,022,716,034	1,650,035,294
65	Total Deferred Credits (lines 56 through 64)		22,885,500,568	14,224,859,405
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		104,237,627,158	86,761,383,154

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 column in 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	20,627,134,250	18,842,698,287		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	12,450,954,263	21,770,132,822		
5	Maintenance Expenses (402)	320-323	3,289,692,994	2,572,214,173		
6	Depreciation Expense (403)	336-337	3,152,310,569	2,915,778,086		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	268,182,440	312,345,977		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		44,858,959	2,113,770		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		12,060,000	2,613		
13	(Less) Regulatory Credits (407.4)		1,232,030,318			
14	Taxes Other Than Income Taxes (408.1)	262-263	687,990,525	676,420,547		
15	Income Taxes - Federal (409.1)	262-263	-18,742,076	457,455		
16	- Other (409.1)	262-263	15,226,597	168,031,963		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	987,062,652	367,396,283		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	352,833,793	3,619,594,973		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,930,139	9,459,742		
21	Losses from Disp. of Utility Plant (411.7)		1,764,604			
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		19,304,567,277	25,155,838,974		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,322,566,973	-6,313,140,687		

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		Line No.
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)	
15,790,806,398	14,242,164,773	4,836,327,852	4,600,533,514			2
						3
9,856,775,900	19,399,846,326	2,594,178,363	2,370,286,496			4
2,673,921,209	1,839,076,052	615,771,785	733,138,121			5
2,461,733,443	2,237,751,122	690,577,126	678,026,964			6
						7
192,418,079	218,499,956	75,764,361	93,846,021			8
						9
44,858,959	2,113,770					10
						11
12,060,000	2,613					12
1,014,812,993		217,217,325				13
497,930,437	498,485,612	190,060,088	177,934,935			14
-18,788,436	-20,429,813	46,360	20,887,268			15
-43,266,945	85,600,295	58,493,542	82,431,668			16
465,052,214	573,464,127	522,010,438	-206,067,844			17
24,320,202	3,728,166,990	328,513,591	-108,572,017			18
						19
1,930,127	6,641,455	12	2,818,287			20
1,764,604						21
						22
						23
						24
15,103,396,142	21,099,601,615	4,201,171,135	4,056,237,359			25
687,410,256	-6,857,436,842	635,156,717	544,296,155			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		1,322,566,973	-6,313,140,687		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility 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)		6,120,577			
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	29,086,863	-91,657		
37	Interest and Dividend Income (419)		56,861,975	131,791,178		
38	Allowance for Other Funds Used During Construction (419.1)		140,080,186	79,271,096		
39	Miscellaneous Nonoperating Income (421)		21,522,402	14,613,757		
40	Gain on Disposition of Property (421.1)		81,540	4,832,442		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		253,753,543	230,416,816		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		43,530,137			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		8,172,778	9,792,051		
46	Life Insurance (426.2)					
47	Penalties (426.3)		25,533,353	49,111,094		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		7,796,638	7,827,488		
49	Other Deductions (426.5)		189,124,167	788,346,091		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		274,157,073	855,076,724		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	651,449	5,078,589		
54	Income Taxes-Other (409.2)	262-263	-1,770,469	-80,871,606		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-121,916,110	6,976,547		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	90,390,785	247,415,278		
57	Investment Tax Credit Adj.-Net (411.5)		-6,991,812	-5,498,780		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-220,417,727	-321,730,528		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		200,014,197	-302,929,380		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		909,242,062	677,880,030		
63	Amort. of Debt Disc. and Expense (428)		49,782,057	126,739,333		
64	Amortization of Loss on Reaquired Debt (428.1)		14,024,025	16,352,937		
65	(Less) Amort. of Premium on Debt-Credit (429)		743,550	743,550		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		142,323	144,644		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		174,148,932	240,449,603		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		34,688,521	54,836,103		
70	Net Interest Charges (Total of lines 62 thru 69)		1,111,622,682	1,005,697,606		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		410,958,488	-7,621,767,673		
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)		410,958,488	-7,621,767,673		

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

Includes interdepartmental operating revenues in Line 2 and operations expenses in Line 4 for the year-to-date period ended December 31:

	2020		2019	
	Revenues	Expenses	Revenues	Expenses
Electric	51,081,618		48,794,887	69,214,107
		72,093,081		
Gas	230,448,154		216,890,392	158,968,136
		169,994,817		
Total	281,529,772		265,685,279	228,182,243
		242,087,898		

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

See footnote in row 2, column c

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		-5,021,494,323	2,598,414,708
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		381,871,625	(7,621,676,016)
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reserves for excess earnings on FERC hydroelectric			
19	project licenses pursuant to Federal Power Act Section 10 (d)	215	2,274,513	
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		2,274,513	
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,759,280	1,766,985
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		-4,635,588,905	(5,021,494,323)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40	Reserves for excess earnings on FERC hydroelectric			

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	project licenses pursuant to Federal Power Act Section 10 (d)		-2,274,513	
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		-2,274,513	
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		286,020,935	286,020,935
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		283,746,422	286,020,935
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		-4,351,842,483	(4,735,473,388)
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-59,869,210	(58,010,567)
50	Equity in Earnings for Year (Credit) (Account 418.1)		29,086,863	(91,657)
51	(Less) Dividends Received (Debit)			
52			-1,759,280	(1,766,986)
53	Balance-End of Year (Total lines 49 thru 52)		-32,541,627	(59,869,210)

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)	410,958,488	-7,621,767,673
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	3,465,351,968	3,230,237,833
5	Disallowed Capital Expenditures	17,075,000	580,881,000
6	Amortization of Unamortized Loss or Gain on Reacquired Debt	13,881,702	16,208,293
7	Amortization of Expenses, Discount and Premium - Long Term Debt	42,542,882	19,417,546
8	Deferred Income Taxes (Net)	1,088,231,805	-2,945,141,198
9	Investment Tax Credit Adjustment (Net)	-6,991,812	-5,498,780
10	Net (Increase) Decrease in Receivables	1,686,127,869	-102,302,285
11	Net (Increase) Decrease in Inventory	5,575,918	-79,838,426
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-742,272,258	1,737,800,074
14	Net (Increase) Decrease in Other Regulatory Assets	-8,410,713,378	-1,116,620,873
15	Net Increase (Decrease) in Other Regulatory Liabilities	6,353,639,907	-302,763,969
16	(Less) Allowance for Other Funds Used During Construction	140,080,186	79,271,096
17	(Less) Undistributed Earnings from Subsidiary Companies	36,097,456	-1,866,004
18	Other (provide details in footnote):	-21,747,716,028	11,473,354,719
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	-18,000,485,579	4,806,561,169
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-7,709,459,133	-6,313,356,194
27	Gross Additions to Nuclear Fuel	-120,482,321	-77,742,004
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-140,080,186	-79,271,096
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-7,689,861,268	-6,311,827,102
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	14,055,510	11,111,891
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-51,407,722	-1,740,858
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 (provide details in footnote):		
54	Proceeds from nuclear decommissioning trust investments	1,517,679,122	956,151,549
55	Purhcases of nuclear decommissioning trust investments and other	-1,589,720,889	-1,032,116,370
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-7,799,255,247	-6,378,420,890
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	10,335,736,841	1,753,430,038
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	2,055,000,000	
67	Other (provide details in footnote):		
68	Equity contribution from PG&E Corporation	12,986,032,164	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	25,376,769,005	1,753,430,038
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-100,000,000	-350,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Customer Advances for Construction	60,348,682	52,905,338
78	Net Decrease in Short-Term Debt (c)		
79	Other	-265,198,830	-56,559,554
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	25,071,918,857	1,399,775,822
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-727,821,969	-172,083,899
87			
88	Cash and Cash Equivalents at Beginning of Period	1,126,277,526	1,298,361,425
89			
90	Cash and Cash Equivalents at End of period	398,455,557	1,126,277,526

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

FOOTNOTE DATA

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

This consists of the following:

	<u>2020</u>	<u>2019</u>
Reorganization items, net	\$ (90,022,642)	\$ 97,219,505
(Increase) Decrease in Other Working Capital	(4,917,289,575)	(116,452,698)
Increase (Decrease) - Other Noncurrent Liabilities*	(16,850,824,242)	11,382,266,594
Others		
Nuclear Fuel Lease Amortization	109,539,888	112,531,507
Payment on capital lease obligation	(1,793,542)	(1,682,542)
Collateral Adjustment	(22,326,176)	6,681,592
Bad Debt Expense	150,027,701	45,946,087
Tax benefit on stock option exercises (shortfall)	(15,508,918)	(17,193,126)
Other-net**	(109,518,522)	(35,962,200)
	-----	-----
Total	\$ (21,747,716,028)	\$ 11,473,354,719
	=====	=====

*In 2019, this primarily consisted of a \$11.4 billion increase to the "Accumulated Provision" balances (accounts 228.2, 228.3, 228.4 and 229) corresponding to the amount charged related to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire. In 2020, this amount primarily consists of the payment of the amounts charged related to those fires.

**This primarily consists of allowances related to GHG.

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

See footnote in column (b), Line 18.

Schedule Page: 120 Line No.: 55 Column: b

This consists of the following:

	<u>2020</u>	<u>2019</u>
Purchases of Nuclear Decommissioning Trust Investments	\$ (1,589,720,889)	\$ (1,032,127,312)
Decrease in other investments	-	10,942
	-----	-----
Total	\$ (1,589,720,889)	\$ (1,032,116,370)

Schedule Page: 120 Line No.: 55 Column: c

See footnote in column (b), Line 55.

Schedule Page: 120 Line No.: 79 Column: b

This consists of the following:

	<u>2020</u>	<u>2019</u>
Increase (Decrease) in customer deposits	\$ (63,665,256)	\$ (53,417,848)
Employee taxes paid for withheld shares	(6,243,287)	(6,712,463)
Affiliate Letter of Credit draw	-	3,570,757
Bridge facility financing fees	(33,260,990)	-
Other debt issuance and exchange fees	(162,029,297)	-
	-----	-----
Total	\$ (265,198,830)	\$ (56,559,554)
	=====	=====

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 79 Column: c

See footnote in column (b), Line 79.

Schedule Page: 120 Line No.: 90 Column: b

This consists of the following:

	<u>2020</u>	<u>2019</u>
Cash (131)	\$ 59,291,720	\$ 294,434,921
Special Deposits (132-134)	143,144,862	7,195,190
Working Funds (135)	18,975	147,415
Temporary Cash Investment (136)	196,000,000	824,500,000
	-----	-----
Total	\$ 398,455,557	\$ 1,126,277,526
	=====	=====

Supplemental disclosure of cash flow information (in millions):

Cash paid for:

Interest (net of amounts capitalized)	\$ (1,458)	\$ (7)
---------------------------------------	------------	--------

Supplemental disclosures of noncash investing and financing activities:

Capital expenditures financed through accounts payable	515	826
Operating lease liabilities arising from obtaining ROU assets	13	2,807
Common stock equity infusion from PG&E Corporation used to satisfy liabilities	6,750	-
Transfer of receivables to subsidiary company	1,504	-

Schedule Page: 120 Line No.: 90 Column: c

See footnote in column (b), Line 90.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/13/2021	Year/Period of Report End of <u>2020/Q4</u>
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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 Commission 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.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Introduction:

The notes below are excerpts from PG&E Corporation and the Utility's combined Report on Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission ("SEC") on February 25, 2021. The following disclosures contain information in accordance with SEC reporting requirements. As such, due to the differences between FERC and SEC reporting requirements, certain amounts disclosed in the following notes may not agree to balances in the FERC financial statements.

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). The primary differences from the Utility's GAAP basis financial statements as presented in the Form 1 are that (1) subsidiaries are not consolidated and are shown under the equity method of accounting, (2) deferred income tax assets and liabilities are not offset against each other but are shown as separate items on the balance sheet, are long-term, and exclude the impact of uncertain temporary tax positions, (3) cost of removal is reported in accumulated depreciation for FERC reporting purposes (GAAP requires that cost of removal be classified as a regulatory liability), (4) there is no current liability classification of the current portion of long-term debt for FERC reporting, (5) there is no reclassification of balancing accounts from current assets to current liabilities for FERC reporting, (6) interdepartmental revenues and expenses between electric and gas operations of the Utility are not eliminated for FERC reporting, (7) penalties and disallowances are reported in other income deductions for FERC reporting, and (8) payments on capital lease obligations are disclosed in operating activities in the statement of cash flows, (9) debt issuance costs are not deducted from the carrying amount of that debt liability for FERC reporting, (10) there is no current liability classification of the current portion of accumulated provision for injuries and damages, in which the estimated losses associated with third-party wildfire claims are recorded, for FERC reporting, (11) FERC reporting does not reclass non-service costs related to pension benefits on the income statement pursuant to ASU 2017-07, (12) there are no separate reporting categories included on the FERC balance sheet for lease assets and liabilities pursuant to ASU 2016-02, (13) there is no reclassification to liabilities subject to compromise for FERC reporting, and (14) there is no reclassification of bankruptcy-related costs to reorganization costs for FERC reporting.

Subsequent Events:

Management has evaluated the impact of events occurring after December 31, 2020 up to February 25, 2021, the date that Pacific Gas and Electric Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 13, 2021. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Energy Storage Assets (FERC Order No. 784):

The following disclosure has been included to comply with accounting and reporting guidance issued by the FERC for new electric storage technologies as a result of FERC Order No. 784.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Energy Plant Account

Energy storage assets totaled \$30,056,380 at December 31, 2020, all of which is recorded in account 363 in accordance with FERC Order No. 784.

Power Purchased Account

Energy storage-related purchased power costs totaled \$187,246 for the year ended December 31, 2020, all of which is recorded in account 555.1 in accordance with FERC Order No. 784.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses totaled \$0 for the year ended December 31, 2020, of which \$0 is recorded in account 582 and \$0 is recorded in account 588. Amounts associated with distribution functional use would have been recorded in account 584.1 and amounts associated with production functional use would have been recorded in account 548.1, in accordance with FERC Order No. 784. Please see table below.

Energy storage-related maintenance expenses totaled \$52,154 for the year ended December 31, 2020, of which \$0 is recorded in account 570 and \$52,154 is recorded in account 592. Amounts associated with distribution functional use would have been recorded in account 592.2 and amounts associated with production functional use would have been recorded in account 553.1, in accordance with FERC Order No. 784. Please see table below.

Other Expense Accounts

Energy storage-related employee pension and benefits expenses are recorded in account 926 in the amount of \$0 for the year ended December 31, 2020.

Energy storage-related payroll tax expenses are recorded in account 408.1 in the amount of \$0 for the year ended December 31, 2020.

The following information to be reported in the newly adopted schedule pages 419-420 can be submitted as part of pages 122-123:

Energy Storage Operations (Small Plants)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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NOTES TO FINANCIAL STATEMENTS (Continued)

Line no.	Name of Energy Storage Project	Functional classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Vaca-Dixon	Production	Vacaville, CA	\$9,199,887	\$0	\$0	\$0	\$187,246	\$0
2	Hitachi	Distribution	San Jose, CA	\$20,856,493	\$0	\$49,141	\$0	\$0	\$0
3	Browns Valley	Distribution	Marysville, CA	\$0	\$0	\$3,013	\$0	\$0	\$0
Totals				\$30,056,380	\$0	\$52,154	\$0	\$187,246	\$0

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

Organization and Basis of Presentation

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, wildfire-related liabilities, legal and regulatory contingencies, the Wildfire Fund, environmental remediation liabilities, AROs, insurance receivables, and pension and other post-retirement benefit plan obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows during the period in which such change occurred.

Chapter 11 Filing and Going Concern

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The accompanying Consolidated Financial Statements have been prepared on a going concern basis, which contemplates the continuity of operations, the realization of assets and the satisfaction of liabilities in the normal course of business. PG&E Corporation and the Utility suffered material losses as a result of the 2017 Northern California wildfires and the 2018 Camp fire, which contributed to the decision to file for Chapter 11 protection on January 29, 2019. Uncertainty regarding these matters previously raised substantial doubt about PG&E Corporation's and the Utility's abilities to continue as going concerns.

As a result of PG&E Corporation's and the Utility's emergence from Chapter 11 on the Effective Date of July 1, 2020, substantial doubt has been alleviated regarding the Company's ability to meet its obligations as they become due within one year after the date the financial statements were issued. (For more information regarding the Chapter 11 Cases, see Note 2 below.)

NOTE 2: BANKRUPTCY FILING

Chapter 11 Proceedings

On the Petition Date, PG&E Corporation and the Utility commenced the Chapter 11 Cases with the Bankruptcy Court. Prior to the Effective Date, PG&E Corporation and the Utility continued to operate their business as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

Except as otherwise set forth in the Plan, the Confirmation Order or another order of the Bankruptcy Court, substantially all pre-petition liabilities were discharged under the Plan.

Significant Bankruptcy Court Actions

Plan of Reorganization and Restructuring Support Agreements

On June 19, 2020, PG&E Corporation and the Utility and the Shareholder Proponents filed the Plan. On June 20, 2020, the Bankruptcy Court confirmed the Plan by issuing the Confirmation Order. PG&E Corporation and the Utility emerged from Chapter 11 on the Effective Date of July 1, 2020.

On September 22, 2019, PG&E Corporation and the Utility entered into the Subrogation RSA with certain holders of wildfire insurance subrogation claims (such claims, the "Subrogation Claims"). On December 19, 2019, the Bankruptcy Court entered an order approving the Subrogation RSA. As of December 31, 2020, PG&E Corporation and the Utility incurred \$53 million in professional fees related to the Subrogation RSA. See "Restructuring Support Agreement with Holders of Subrogation Claims" in Note 14 for further information on the Subrogation RSA.

On December 6, 2019, PG&E Corporation and the Utility entered the TCC RSA, which was subsequently amended on December 16, 2019, with the TCC, the attorneys and other advisors and agents for holders of claims against PG&E Corporation and the Utility relating to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire (other than the Subrogation Claims and Public Entity Wildfire Claims (as defined below)) (the "Fire Victim Claims") that are signatories to the TCC RSA, and the Shareholder Proponents. On December 19, 2019, the Bankruptcy Court entered an order approving the TCC RSA. See "Restructuring Support Agreement with the TCC" in Note 14 for further information on the TCC RSA.

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On January 22, 2020, PG&E Corporation and the Utility entered into the Noteholder RSA with those holders of senior unsecured debt of the Utility that are identified as “Consenting Noteholders” therein and the Shareholder Proponents. On February 5, 2020, the Bankruptcy Court entered an order approving the Noteholder RSA.

Confirmation of the Plan of Reorganization

The Plan as confirmed by the Confirmation Order provides for certain transactions and the satisfaction and treatment of claims against and interests in PG&E Corporation and the Utility, each in accordance with the terms of the Plan, including the transactions described below. The Plan provides for the following treatment of various classes of claims as described below. PG&E Corporation and the Utility are in the process of resolving and paying claims pursuant to the treatment provided under the Plan.

- PG&E Corporation and the Utility funded the Fire Victim Trust for the benefit of all holders of Fire Victim Claims, whose claims were channeled to the Fire Victim Trust on the Effective Date with no recourse to PG&E Corporation and the Utility. In full and final satisfaction, release, and discharge of all Fire Victim Claims, the Fire Victim Trust was funded with \$5.4 billion in cash (with an additional \$1.35 billion in cash to be funded on a deferred basis), common stock of PG&E Corporation representing 22.19% of the outstanding common stock of PG&E Corporation as of the Effective Date (subject to potential adjustments), plus the assignment of certain rights and causes of action. As a result of such funding, all Fire Victim Claims have been satisfied, released, discharged and channeled to the Fire Victim Trust with no recourse to PG&E Corporation or the Utility;
- PG&E Corporation and the Utility funded a trust (the “Subrogation Wildfire Trust”) for the benefit of holders of Subrogation Claims in the amount of \$11.0 billion in cash. Such amount was initially funded into escrow and later paid to the Subrogation Wildfire Trust. As a result of such funding, all Subrogation Claims have been satisfied, released and discharged and channeled to the Subrogation Wildfire Trust with no recourse to PG&E Corporation or the Utility;
- PG&E Corporation and the Utility paid \$1.0 billion in cash to certain local public entities (the “Settling Public Entities”) that entered into PSAs with PG&E Corporation and the Utility and established a segregated fund in the amount of \$10 million to be used to reimburse the Settling Public Entities for any and all legal fees and costs associated with the defense or resolution of any third party claims against the Settling Public Entities in full and final satisfaction, release and discharge of such Settling Public Entities’ wildfire related claims;
- The following pre-petition notes of the Utility: (a) 3.50% Senior Notes due October 1, 2020; (b) 4.25% Senior Notes due May 15, 2021; (c) 3.25% Senior Notes due September 15, 2021; and (d) 2.45% Senior Notes due August 15, 2022), (collectively, the “Utility Short-Term Senior Notes”); the following pre-petition notes of the Utility: (a) 6.05% Senior Notes due March 1, 2034; (b) 5.80% Senior Notes due March 1, 2037; (c) 6.35% Senior Notes due February 15, 2038; (d) 6.25% Senior Notes due March 1, 2039; (e) 5.40% Senior Notes due January 15, 2040; and (f) 5.125% Senior Notes due November 15, 2043, (collectively, the “Utility Long-Term Senior Notes) and the pre-petition credit agreements of the Utility, including in connection with the pollution control bonds (except for \$100 million of pollution control bonds (Series 2008F and 2010E), which were repaid in cash) (collectively, the “Utility Funded Debt”) were refinanced and all other Utility pre-petition senior notes (collectively, the “Utility Reinstated Senior Notes”) were reinstated and collateralized on or around the Effective Date through the issuance of a corresponding series of first mortgage bonds of the Utility;
- PG&E Corporation paid in full all of its pre-petition funded debt obligations that were allowed in the Chapter 11 Cases;

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- PG&E Corporation and the Utility repaid all borrowings under the DIP Facilities and have paid all other allowed administrative expense claims in accordance with the Plan;
- Holders of allowed claims by a governmental authority entitled to priority in payment under sections 502(i) and 507(a)(8) of the Bankruptcy Code (“Priority Tax Claims”) have received or will receive in the future, cash in an amount equal to such allowed Priority Tax Claims;
- Holders of allowed secured claims other than Priority Tax Claims or secured claims related to the DIP Facilities (“Other Secured Claims”) have received or will receive cash in an amount equal to such Other Secured Claims;
- Holders of allowed claims other than administrative expense claims or Priority Tax Claims, entitled to priority in payment as specified in section 507(a)(3), (4), (5), (6), (7), or (9) of the Bankruptcy Code (“Priority Non-Tax Claims”) have received or will receive cash in an amount equal to such allowed Priority Non-Tax Claims;
- PG&E Corporation and the Utility will pay in full all pre-petition unsecured claims that do not fall within any of the other classes of unsecured claims under the Plan (“General Unsecured Claims”) that are allowed in the Chapter 11 Cases; and
- PG&E Corporation and the Utility will pay in full all allowed claims that are subject to subordination under section 510(b) of the Bankruptcy Code other than subordinated claims related to the common stock of PG&E Corporation (“Subordinated Debt Claims”). PG&E Corporation will provide to each holder of an allowed claim that relates to the common stock of PG&E Corporation that is subject to subordination under section 510(b) of the Bankruptcy Code (a “HoldCo Rescission or Damage Claim”) a number of shares of PG&E Corporation common stock based on a formula as specified in the Plan that varies depending on when the claimant purchased the affected shares of common stock and reduces the amount of the allowed claim by the amount of insurance proceeds, if any, received by the claimant on account of all or any portion of an allowed HoldCo Rescission or Damage Claim.

In addition, the Plan also provides for the following in connection with or following the implementation of the Plan:

- Holders of claims related to the 2016 Ghost Ship fire are entitled to pursue their claims against PG&E Corporation and the Utility (with any recovery being limited to amounts available under PG&E Corporation’s and the Utility’s insurance policies for the 2016 year);
- Holders of certain claims may be able to pursue their claims against PG&E Corporation and the Utility, such as administrative expense claims that have not been satisfied or come due by the Effective Date, claims arising from wildfires occurring after the Petition Date that have not been satisfied by the Effective Date (including the 2019 Kincadee fire (as defined in Note 14 below)), and claims relating to certain FERC refund proceedings, workers’ compensation benefits and certain environmental claims;
- PG&E Corporation or the Utility, as applicable, assumed all of their respective power purchase agreements and community choice aggregation servicing agreements; and
- PG&E Corporation or the Utility, as applicable, assumed all of their respective pension obligations, other employee obligations, and collective bargaining agreements with labor.

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The Confirmation Order contains a channeling injunction that is also in the Plan that provides, among other things, that the sole source of recovery for holders of Subrogation Claims will be from the Subrogation Wildfire Trust and the sole source of recovery for holders of Fire Victim Claims will be from the Fire Victim Trust. The holders of such claims will have no recourse to or claims whatsoever against PG&E Corporation and the Utility or their assets and properties on account of such claims.

The Plan as confirmed by the Confirmation Order provides for certain financing transactions as follows:

- one or more equity offerings of up to \$9.0 billion of gross proceeds in cash through the issuance of common stock and/or other equity and/or equity-linked securities pursuant to one or more offerings and/or private placements;
- the issuance of \$4.75 billion of new PG&E Corporation debt;
- the reinstatement of \$9.575 billion of pre-petition debt of the Utility; and
- the issuance of \$23.775 billion of new Utility debt, consisting of (i) \$6.2 billion of the Utility’s 4.55% Senior Notes due 2030 and 4.95% Senior Notes due 2050 (the “New Utility Long-Term Bonds”) to be issued to holders of certain pre-petition senior notes of the Utility pursuant to the Plan, (ii) \$1.75 billion of the Utility’s 3.45% Senior Notes due 2025 and 3.75% Senior Notes due 2028 (the “New Utility Short-Term Bonds”) to be issued to holders of certain pre-petition senior notes of the Utility pursuant to the Plan, (iii) \$3.9 billion of the Utility’s 3.15% Senior Notes due 2026 and 4.50% Senior Notes due 2040 (the “New Utility Funded Debt Exchange Bonds”) to be issued to holders of certain pre-petition indebtedness of the Utility pursuant to the Plan and (iv) \$11.925 billion of new debt securities or bank debt of the Utility to be issued to third parties for cash on or prior to the Effective Date (of which \$6.0 billion is expected to be repaid with the proceeds of a new securitization transaction after the Effective Date) (see Note 5 below for a description of the debt transactions that occurred on or before the Effective Date).

The foregoing financing transactions occurred on or around the Effective Date.

On the Effective Date, pursuant to the Plan, the Utility entered into a tax benefits payment agreement (the “Tax Benefits Payment Agreement”) with the Fire Victim Trust, pursuant to which the Utility agreed to pay to the Fire Victim Trust in cash an aggregate amount of \$1.35 billion, comprising (i) at least \$650 million of tax benefits arising from certain tax deductions related to pre-petition wildfires (“Tax Benefits”) for fiscal year 2020 to be paid on or before January 15, 2021 and (ii) of the remainder of \$1.35 billion of Tax Benefits for fiscal year 2021 to be paid on or before January 15, 2022. On January 15, 2021, the Utility paid the first tranche of tax benefits of approximately \$758 million pursuant to the Tax Benefits Payment Agreement.

Also on the Effective Date, pursuant to the Plan, the Utility entered into an assignment agreement with the Fire Victim Trust (the “Fire Victim Trust Assignment Agreement”), pursuant to which the Utility agreed to transfer to the Fire Victim Trust on the Effective Date 477.0 million shares of PG&E Corporation common stock. As a result of the Additional Units Issuance (as described in Note 6 below) on August 3, 2020, PG&E Corporation made an equity contribution of 748,415 shares to the Utility which delivered such additional shares of common stock to the Fire Victim Trust pursuant to an anti-dilution provision in the Fire Victim Trust Assignment Agreement.

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Further, on the Effective Date, PG&E Corporation and the Utility funded a \$10 million fund established for the benefit of the Supporting Public Entities (refer to “Plan Support Agreements with Public Entities” in Note 14 below) under the PSAs in accordance with the terms of the Plan and the PSAs with the Supporting Public Entities, and also made a payment of \$1.0 billion in cash to the public entities who are party to the PSAs with the Supporting Public Entities. Also, on the Effective Date, PG&E Corporation and the Utility funded \$100 million to the Subrogation Wildfire Trust and placed the balance of the \$11.0 billion in a segregated escrow account established and owned by the Subrogation Wildfire Trust for the benefit of holders of Subrogation Claims, which was subsequently paid to the Subrogation Wildfire Trust.

Equity Financing

In connection with its emergence from Chapter 11 in July 2020, PG&E raised an aggregate of \$9.0 billion of gross proceeds through the issuance of common stock and other equity-linked instruments. For more information, see Note 6 below.

Equity Backstop Commitments and Forward Stock Purchase Agreements

As of March 6, 2020, PG&E Corporation entered into Chapter 11 Plan Backstop Commitment Letters (collectively, as amended by the Consent Agreements (as defined below), the “Backstop Commitment Letters”) with the Backstop Parties, pursuant to which the Backstop Parties severally agreed to fund up to \$12.0 billion of proceeds to finance the Plan through the purchase of PG&E Corporation common stock, subject to the terms and conditions set forth in such Backstop Commitment Letters (the “Backstop Commitments”). As a result of PG&E Corporation emerging from Chapter 11 on July 1, 2020, the Backstop Commitments were not utilized and terminated in accordance with their terms.

The commitment premium for the Backstop Commitments was paid in shares (the “Backstop Commitment Premium Shares”) of PG&E Corporation’s common stock (with each Backstop Party receiving its pro rata share of 119 million shares of PG&E Corporation’s common stock based on the proportion of the amount of such Backstop Party’s Backstop Commitment to \$12.0 billion). PG&E Corporation issued the Backstop Commitment Premium Shares to the Backstop Parties on the Effective Date in connection with emerging from Chapter 11.

On June 30, 2020, PG&E Corporation recorded approximately \$1.1 billion of expense related to the Backstop Commitment Premium Shares in Reorganization items, net (as defined below). This amount was primarily based on PG&E Corporation’s closing stock price on June 30, 2020 of \$8.87 per share. On the Effective Date, PG&E Corporation’s closing price was \$9.03 per share and as a result, PG&E Corporation recorded an additional \$19 million expense in the third quarter of 2020.

Under the Backstop Commitment Letters, PG&E Corporation and the Utility have also agreed to reimburse the Backstop Parties for reasonable professional fees and expenses of up to \$34 million in the aggregate for the legal advisors and \$19 million in the aggregate for the financial advisor, upon the terms and conditions set forth in the Backstop Commitment Letters. As of December 31, 2020, PG&E Corporation recorded \$49 million in professional fees and related expenses to the Backstop Parties in Reorganization items, net.

In connection with PG&E Corporation’s underwritten offerings of up to \$5.75 billion of equity securities to finance the transactions contemplated by the Plan (the “Offerings”), up to \$523 million was issuable pursuant to customary options granted to the underwriters thereof to purchase the Option Securities (as defined below in Note 6).

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On June 19, 2020, PG&E Corporation entered into the Forward Stock Purchase Agreements with the Backstop Parties. Each Forward Stock Purchase Agreement provided that, subject to certain conditions, the Backstop Party would purchase on the Effective Date, and receive on such settlement date as designated in the Forward Stock Purchase Agreement (the "Settlement Date") an amount of common stock of PG&E Corporation (such shares, each Backstop Party's "Greenshoe Backstop Shares") equal to its pro rata share of the value of the Option Securities not purchased by the underwriters (such amount, each Backstop Party's "Greenshoe Backstop Purchase Amount" and all Greenshoe Backstop Purchase Amounts in the aggregate, the "Aggregate Greenshoe Backstop Purchase Amount"), at a price per share equal to the lesser of (i) the lowest per share price of common stock sold on an underwritten basis to the public in an offering of common stock of PG&E Corporation, as disclosed on the cover page of the prospectus or prospectus supplement, and (ii) the price per share payable by the investors party to the Investment Agreement dated as of June 7, 2020 (such lesser price, the "Settlement Price"). The Settlement Price was \$9.50 per share. Each Forward Stock Purchase Agreement expired on August 3, 2020.

On June 25, 2020, the Backstop Parties funded the Greenshoe Backstop Purchase Amount to PG&E Corporation in the amount of \$523 million, which was recorded in Other current liabilities on the Consolidated Financial Statements. PG&E Corporation applied the proceeds of such funding to distributions under the Plan on the Effective Date. On August 3, 2020, PG&E Corporation redeemed \$120.5 million of the Forward Stock Purchase Agreements payable in cash as a result of the exercise by the underwriters of their option to purchase Equity Units pursuant to the Equity Units Underwriting Agreement (as defined below in Note 6). On August 3, 2020, PG&E Corporation delivered 42.3 million Greenshoe Backstop Shares to the Backstop Parties to settle the portion of the Forward Stock Purchase Agreements that was not redeemed.

Additionally, each Forward Stock Purchase Agreement provided that, subject to the consummation by PG&E Corporation of the Offerings, PG&E Corporation would issue to each Backstop Party its pro rata share of 50 million shares of common stock (such shares, each Backstop Party's "Additional Backstop Premium Shares"). The Additional Backstop Premium Shares were issued to Backstop Parties on the Effective Date. On June 30, 2020, PG&E Corporation recorded \$444 million of expense related to the Additional Backstop Premium Shares in Reorganization items, net. This amount was based primarily on PG&E Corporation's closing stock price on June 30, 2020 of \$8.87 per share. On the Effective Date, PG&E Corporation's closing stock price was \$9.03 per share and as a result, PG&E Corporation recorded an additional \$8 million expense in the third quarter of 2020.

Financial Reporting in Reorganization

Effective on the Petition Date and up to June 30, 2020, PG&E Corporation and the Utility applied accounting standards applicable to reorganizations, which are applicable to companies under Chapter 11 bankruptcy protection. These accounting standards require the financial statements for periods subsequent to the Petition Date to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Expenses, realized gains and losses, and provisions for losses that were directly associated with reorganization proceedings must have been reported separately as reorganization items, net in the Consolidated Statements of Income. In addition, the balance sheet must have distinguished pre-petition LSTC of PG&E Corporation and the Utility from pre-petition liabilities that were not subject to compromise, post-petition liabilities, and liabilities of the subsidiaries of PG&E Corporation that were not debtors in the Chapter 11 Cases in the Consolidated Balance Sheets. LSTC are pre-petition obligations that were not fully secured and had at least a possibility of not being repaid at the full claim amount. Where there was uncertainty about whether a secured claim would be paid or impaired pursuant to the Chapter 11 Cases, PG&E Corporation and the Utility classified the entire amount of the claim as LSTC.

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Furthermore, the realization of assets and the satisfaction of liabilities are subject to uncertainty. Pursuant to the Plan and Confirmation Order, actions to enforce or otherwise effect the payment of certain claims against PG&E Corporation and the Utility in existence before the Petition Date were subject to an injunction and were subject to treatment under the Plan. These claims were reflected as LSTC in the Consolidated Balance Sheets at December 31, 2019. Additional claims may arise for contingencies and other unliquidated and disputed amounts.

PG&E Corporation's Consolidated Financial Statements are presented on a consolidated basis and include the accounts of PG&E Corporation and the Utility and other subsidiaries of PG&E Corporation and the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

The Utility's Consolidated Financial Statements are presented on a consolidated basis and include the accounts of the Utility and other subsidiaries of the Utility that individually and in aggregate are immaterial. Such other subsidiaries did not file for bankruptcy.

Upon emergence from Chapter 11 on July 1, 2020, PG&E Corporation and the Utility were not required to apply fresh start accounting based on the provisions of ASC 852 since the entity's reorganization value immediately before the date of confirmation was more than the total of all its post-petition liabilities and allowed claims.

Liabilities Subject to Compromise

As a result of the commencement of the Chapter 11 Cases, the payment of pre-petition liabilities was subject to compromise or other treatment pursuant to the Plan. Generally, actions to enforce or otherwise effect payment of pre-petition liabilities are subject to an injunction and will be satisfied pursuant to the Plan and the Chapter 11 claims reconciliation process.

Prior to June 30, 2020, pre-petition liabilities that were subject to compromise were required to be reported at the amounts expected to be allowed. Therefore, liabilities subject to compromise as of December 31, 2019 in the table below reflected management's estimates of amounts expected to be allowed in the Chapter 11 Cases, based upon, among other things, the status of negotiations with creditors. As of June 30, 2020, such amounts were reclassified to current or non-current liabilities in the Condensed Consolidated Balance Sheets, based upon management's judgment as to the timing for settlement of such liabilities.

Liabilities subject to compromise as of December 31, 2019 which were settled or reclassified as of December 31, 2020 consist of the following:

(in millions)	Utility	PG&E Corporation (1)	December 31, 2019 PG&E Corporation Consolidated	Change in Estimated Allowed Claim 2020 (2)	Cash Payment	Reclassified as of June 30, 2020 (3)	Utility	PG&E Corporation (1)	December 31, 2020 PG&E Corporation Consolidated
	22,450								
Financing debt	\$	\$ 666	\$ 23,116	\$ 351	\$ —	\$ (23,467)	\$ —	\$ —	\$ —
Wildfire-related claims	25,548	—	25,548	18	(23)	(25,543)	—	—	—
Trade creditors (4)	1,183	5	1,188	6	(14)	(1,180)	—	—	—
Non-qualified	20	137	157	—	—	(157)	—	—	—

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benefit plan										
2001 bankruptcy										
disputed claims	234	—	234	4	—	(238)	—	—	—	—
Customer deposits & advances	71	—	71	12	—	(83)	—	—	—	—
Other	230	2	232	59	—	(291)	—	—	—	—
Total Liabilities Subject to Compromise	49,736	810	50,546	450	(37)	(50,959)	—	—	—	—

- (1) PG&E Corporation amounts reflected under the column “PG&E Corporation” exclude the accounts of the Utility.
- (2) Change in estimated allowed claim amounts are primarily due to interest accruals with the exception of the “wildfire-related claims,” “customer deposits & advances,” and “other” line items which are mainly due to the adjustment to recorded liabilities.
- (3) Amounts reclassified as of June 30, 2020 included \$8.6 million to Accounts payable - other, \$237.6 million to Disputed claims and customer refunds, \$1,347.4 million to Interest payable, \$21,425.7 million to Long-term debt, \$300.0 million to Short-term borrowings, \$450.0 million to Long-term debt, classified as current, \$301.0 million to Other current liabilities, \$97.9 million to Other non-current liabilities, \$121.3 million to Pension and other post-retirement benefits, \$1,126.9 million to Accounts payable - trade creditors, and \$25,542.7 million to Wildfire-related claims on the Condensed Consolidated Balance Sheets.
- (4) As of February 18, 2021, \$5 million and \$941 million has been repaid by PG&E Corporation and the Utility, respectively.

Chapter 11 Claims Process

PG&E Corporation and the Utility have received over 100,000 proofs of claim since the Petition Date, of which approximately 80,000 were channeled to the Subrogation Wildfire Trust and Fire Victim Trust. The claims channeled to the Subrogation Wildfire Trust and Fire Victim Trust will be resolved by such trusts, and PG&E Corporation and the Utility have no further liability in connection with such claims. PG&E Corporation and the Utility continue their review and analysis of certain remaining claims including asserted litigation claims, trade creditor claims, non-qualified benefit plan claims, along with other tax and regulatory claims, and therefore the ultimate liability of PG&E Corporation or the Utility for such claims may differ from the amounts asserted in such claims. Allowed claims are paid in accordance with the Plan and the Confirmation Order.

The Bankruptcy Code provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation, other than as provided in the Plan or the Confirmation Order.

The Plan, however, provides that the holders of certain claims may pursue their claims against PG&E Corporation and the Utility on or after the Effective Date, including, but not limited to, the following:

- claims arising after the January 29, 2019 Petition Date that constitute administrative expense claims, which will not be discharged pursuant to the Plan, other than allowed administrative expense claims that have been paid in cash or otherwise satisfied in the ordinary course in an amount equal to the allowed amount of such claim on or prior to the Effective Date;
- claims of the Ghost Ship fire litigation (with any recovery being limited to amounts available under PG&E Corporation’s and the Utility’s insurance policies for the 2016 year);

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- claims arising out of or based on the 2019 Kincadee fire (as defined in Note 14 below), which the California Department of Forestry and Fire Protection has determined was caused by the Utility’s transmission lines; which is currently under investigation by the CPUC and the Sonoma County District Attorney’s Office; and which may also be under investigation by various other entities, including law enforcement agencies; and
- certain FERC refund proceedings, workers’ compensation benefits and environmental claims.

Furthermore, holders of certain claims may assert that they are entitled under the Plan or the Bankruptcy Code to pursue, or continue to pursue, their claims against PG&E Corporation and the Utility on or after the Effective Date, including but not limited to, claims arising from or relating to:

- the purported de-energization securities class action filed in October 2019 and amended to add PG&E Corporation in April 2020. For more information on the filing, see Note 14 below;
- the purported PSPS class action filed in December 2019 and seeking up to \$2.5 billion in special and general damages, punitive and exemplary damages and injunctive relief to require the Utility to properly maintain and inspect its power grid, was dismissed on April 3, 2020, and subsequently appealed on April 6, 2020. For more information on the filing, see Note 15 below; and
- indemnification or contributing claims, including with respect to the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire.

In addition, claims continue to be pursued against PG&E Corporation and the Utility and certain of their respective current and former directors and officers as well as certain underwriters, in connection with three purported securities class actions, as further described in Note 14 under the heading “Securities Class Action Litigation.”

Various electricity suppliers filed claims in the Utility’s 2001 prior proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility’s customers between May 2000 and June 2001. While FERC and judicial proceedings are pending, the Utility pursued settlements with electricity suppliers and entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility’s refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties, in some instances, would be subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods. Pursuant to the Plan, on and after the Effective Date, the holders of such claims are entitled to pursue their claims against the Reorganized Utility as if the Chapter 11 Cases had not been commenced.

On September 1, 2020, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court requesting that the court approve an alternative dispute resolution process for resolving disputed general unsecured claims and appoint a panel of mediators in the process. On September 25, 2020, the court approved the motion and appointed a panel of mediators. The mediators’ role will be to assist various claims through a Standard and Abbreviated Mediation Process.

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On October 27, 2020, PG&E Corporation and the Utility filed a motion for entry of an order extending deadline for the reorganized debtors to object to claims, requesting an additional 180 days beyond December 31, 2020 to process claims. On November 17, 2020, the Bankruptcy Court entered an order extending the deadline under the Plan for PG&E Corporation and the Utility to object to claims through and including June 26, 2021 (March 31, 2021, for claims held by the United States), without prejudice to the rights of PG&E Corporation and the Utility to seek additional extensions thereof.

Reorganization Items, Net

Reorganization items, net, represent amounts incurred after the Petition Date as a direct result of the Chapter 11 Cases and are comprised of professional fees and financing costs, net of interest income and other. Cash paid for reorganization items, net was \$102 million and \$400 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2020 as compared to \$15 million and \$223 million for PG&E Corporation and the Utility, respectively, during 2019. Of the \$400 million in cash paid for the Utility's reorganization items, during the year ended December 31, 2020, \$35 million in facility fees related to the Backstop Commitment Letters were recorded to a regulatory asset as they were deemed probable of recovery. Reorganization items, net for the year ended December 31, 2020 include the following:

(in millions)	Year Ended December 31, 2020		
	Utility	PG&E Corporation (1)	PG&E Corporation Consolidated
Debtor-in-possession financing costs	\$ 6	\$ —	\$ 6
Legal and other (2)	318	1,651	1,969
Interest and other	(14)	(2)	(16)
Total reorganization items, net	\$ 310	\$ 1,649	\$ 1,959

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

(2) Amount includes \$1.5 billion in equity backstop premium expense and bridge loan facility fees.

Reorganization items, net from the Petition Date through December 31, 2019 include the following:

(in millions)	Petition Date Through December 31, 2019		
	Utility	PG&E Corporation (1)	PG&E Corporation Consolidated
Debtor-in-possession financing costs	\$ 97	\$ 17	\$ 114
Legal and other	273	19	292
Interest income	(50)	(10)	(60)
Total reorganization items, net	\$ 320	\$ 26	\$ 346

(1) PG&E Corporation amounts reflected under the column "PG&E Corporation" exclude the accounts of the Utility.

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NOTE 3: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation and Regulated Operations

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover “revenue requirements” that have been authorized by the CPUC or the FERC based on the Utility’s cost of providing service. The Utility’s ability to recover a significant portion of its authorized revenue requirements through rates is generally independent, or “decoupled,” from the volume of the Utility’s electricity and natural gas sales. The Utility records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records, as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, the Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income. See “Revenue Recognition” below.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility’s operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Loss Contingencies

A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can reasonably be estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation’s and the Utility’s provision for loss and expense excludes anticipated legal costs, which are expensed as incurred.

Revenue Recognition

Revenue from Contracts with Customers

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The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements. Revenues can vary significantly from period to period because of seasonality, weather, and customer usage patterns.

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rate cases is independent or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, electric and natural gas operating revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility 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, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. As a result, these differences have no impact on net income.

The following table presents the Utility's revenues disaggregated by type of customer:

(in millions)	Year Ended	
	2020	2019
Electric		
Revenue from contracts with customers		
Residential	\$ 5,523	\$ 4,847
Commercial	4,722	4,756
Industrial	1,530	1,493
Agricultural	1,471	1,106
Public street and highway lighting	69	67
Other (1)	(130)	168
Total revenue from contracts with customers - electric	13,185	12,437
Regulatory balancing accounts (2)	673	303
Total electric operating revenue	\$ 13,858	\$ 12,740

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Natural gas

Revenue from contracts with customers

Residential	\$ 2,517	\$ 2,325
Commercial	597	605
Transportation service only	1,211	1,249
Other (1)	61	123
Total revenue from contracts with customers - gas	4,386	4,302
Regulatory balancing accounts (2)	225	87
Total natural gas operating revenue	4,611	4,389
Total operating revenues	\$ 18,469	\$ 17,129

(1) This activity is primarily related to the change in unbilled revenue and amounts subject to refund, partially offset by other miscellaneous revenue items.

(2) These amounts represent revenues authorized to be billed or refunded to customers.

Cash, Cash Equivalents, and Restricted Cash

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value. As of December 31, 2020, the Utility also holds restricted cash that primarily consists of cash held in escrow to be used to pay bankruptcy related professional fees.

Allowance for Doubtful Accounts Receivable and Credit Losses

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectible customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables, current economic conditions, and assessment of customer collectability.

In addition, upon adopting ASU 2016-13, PG&E Corporation and the Utility use the current expected credit loss model to estimate the expected lifetime credit loss on financial assets, including trade and other receivables, rather than incurred losses over the remaining life of most financial assets measured at amortized cost. The guidance also requires use of an allowance to record estimated credit losses on available-for-sale debt securities. See "Financial Instruments - Credit Losses" below for more information.

Inventories

Inventories are carried at weighted-average cost and include natural gas stored underground as well as materials and supplies. Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribution to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropriate, when consumed or installed.

Emission Allowances

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The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets – other and other noncurrent assets – other on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.

Property, Plant, and Equipment

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciation or fair value. Historical costs include labor and materials, construction overhead, and AFUDC. (See “AFUDC” below.) The Utility’s total estimated useful lives and balances of its property, plant, and equipment were as follows:

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31,	
		2020	2019
Electricity generating facilities (1)	5 to 75	\$ 13,751	\$ 13,189
Electricity distribution facilities	10 to 70	37,675	35,237
Electricity transmission facilities	15 to 75	15,556	14,281
Natural gas distribution facilities	20 to 60	15,133	14,236
Natural gas transmission and storage facilities	5 to 66	9,002	8,452
Construction work in progress		2,757	2,675
Other		18	18
Total property, plant, and equipment		93,892	88,088
Accumulated depreciation		(27,756)	(26,453)
Net property, plant, and equipment		\$ 66,136	\$ 61,635

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted-average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 15 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight-line method of depreciation over the useful lives of property, plant, and equipment. The Utility’s composite depreciation rates were 3.76% in 2020, 3.80% in 2019, and 3.82% in 2018. The useful lives of the Utility’s property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

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AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of \$35 million and \$140 million during 2020, \$55 million and \$79 million during 2019, and \$53 million and \$129 million during 2018.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2020 and 2019, including nuclear decommissioning obligations:

(in millions)	2020	2019
ARO liability at beginning of year	\$ 5,854	\$ 5,994
Liabilities incurred in the current period	268	—
Revision in estimated cash flows	53	(376)
Accretion	265	274
Liabilities settled	(28)	(38)
ARO liability at end of year	\$ 6,412	\$ 5,854

The Utility has not recorded a liability related to certain AROs for assets that are expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities associated with substations, certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration of land to the conditions under certain agreements.

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

The total nuclear decommissioning obligation accrued was \$5.1 billion and \$4.9 billion at December 31, 2020 and 2019, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was \$10.6 billion at December 31, 2020 and 2019.

Disallowance of Plant Costs

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PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated.

Nuclear Decommissioning Trusts

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facility from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its debt investments held in the nuclear decommissioning trusts as available-for-sale. Since the Utility's nuclear decommissioning trust assets are managed by external investment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other comprehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Consolidated VIE

The SPV is a bankruptcy remote, limited liability company wholly owned by the Utility, and its assets are not available to creditors of PG&E Corporation or the Utility. Pursuant to the Receivables Securitization Program (as defined in Note 5 below), the Utility sells certain of its receivables and certain related rights to payment and obligations of the Utility with respect to such receivables, and certain other related rights to the SPV, which, in turn, obtains loans secured by the receivables from financial institutions (the "Lenders"). Amounts received from the Lenders, the pledged receivables and the corresponding debt are included in Accounts receivable and Long-term debt, respectively, on the Consolidated Balance Sheets. The aggregate principal amount of the loans made by the Lenders cannot exceed \$1.0 billion outstanding at any time. The Receivables Securitization Program is scheduled to terminate on October 5, 2022, unless extended or earlier terminated.

The SPV is considered a VIE because its equity capitalization is insufficient to support its operations. The most significant activities that impact the economic performance of the SPV are decisions made to manage receivables. The Utility is considered the primary beneficiary and consolidates the SPV as it makes these decisions. No additional financial support was provided to the SPV during the year ended December 31, 2020 or is expected to be provided in the future that was not previously contractually required. As of December 31, 2020, the SPV has \$2.6 billion of net accounts receivable and has outstanding borrowings of \$1.0 billion under the Receivables Securitization Program.

Non-Consolidated VIEs

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Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2020, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2020, it did not consolidate any of them.

Contributions to the Wildfire Fund

On the Effective Date, PG&E Corporation and the Utility contributed, in accordance with AB 1054, an initial contribution of approximately \$4.8 billion and first annual contribution of approximately \$193 million to the Wildfire Fund to secure participation of the Utility therein. On December 30, 2020, the Utility made its second annual contribution of \$193 million to the Wildfire Fund. As of December 31, 2020, PG&E Corporation and the Utility have eight remaining annual contributions of \$193 million. PG&E Corporation and the Utility account for the contributions to the Wildfire Fund similarly to prepaid insurance with expense being allocated to periods ratably based on an estimated period of coverage. The Wildfire Fund is available to pay for eligible claims arising as of July 12, 2019, the effective date of AB 1054, subject to a limit of 40% of the amount of such claims arising between the effective date of AB 1054 and the Utility's emergence from Chapter 11. The 40% limit does not apply to eligible claims that arise after the Utility's emergence from Chapter 11. The Wildfire Fund is additionally limited to the portion of such claims that exceeds the greater of (i) \$1.0 billion in the aggregate in any year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to Section 3293 of the Public Utilities Code, added by AB 1054.

As of December 31, 2020, PG&E Corporation and the Utility recorded \$193 million in Other current liabilities, \$1.3 billion in Other non-current liabilities, \$464 million in current assets - Wildfire fund asset, and \$5.8 billion in non-current assets - Wildfire fund asset in the Consolidated Balance Sheets. As of December 31, 2020, the Utility recorded amortization and accretion expense of \$413 million. The amortization of the asset, accretion of the liability, and if applicable, impairment of the asset is reflected in Wildfire fund expense in the Consolidated Statements of Income. Expected contributions are discounted to the present value using the 10-year US treasury rate at the date PG&E Corporation and the Utility satisfied all the eligibility requirements to participate in the Wildfire Fund. A useful life of 15 years is being used to amortize the Wildfire Fund asset.

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AB 1054 did not specify a period of coverage; therefore, this accounting treatment is subject to significant accounting judgments and estimates. In estimating the period of coverage, PG&E Corporation and the Utility use a Monte Carlo simulation that began with 12 years of historical, publicly available fire-loss data from wildfires caused by electrical equipment, and subsequently plan to add an additional year of data each following year. The period of historic fire-loss data and the effectiveness of mitigation efforts by the California electric utility companies are significant assumptions used to estimate the useful life. These assumptions along with the other assumptions below create a high degree of uncertainty related to the estimated useful life of the Wildfire Fund. The simulation results in the estimated number and severity of catastrophic fires that could occur in California within the participating electric utilities' service territories during the term of the Wildfire Fund. Starting with a 5-year period of historical data, with average annual statewide claims or settlements of approximately \$6.5 billion, compared to approximately \$2.9 billion for the 12-year historical data, would have decreased the amortization period to 6 years. Similarly, a 10% change to the assumption around current and future mitigation effort effectiveness would increase the amortization period to 17 years assuming greater effectiveness and would decrease the amortization period to 12 years assuming less effectiveness.

Other assumptions used to estimate the useful life include the estimated cost of wildfires caused by other electric utilities, the amount at which wildfire claims would be settled, the likely adjudication of the CPUC in cases of electric utility-caused wildfires, the impacts of climate change, the level of future insurance coverage held by the electric utilities, the FERC-allocable portion of loss recovery, and the future transmission and distribution equity rate base growth of other electric utilities. Significant changes in any of these estimates could materially impact the amortization period.

PG&E Corporation and the Utility evaluate all assumptions quarterly, or upon claims being made from the Wildfire Fund for catastrophic wildfires, and the expected life of the Wildfire Fund will be adjusted as required. The Wildfire Fund is available to other participating utilities in California and the amount of claims that a participating utility incurs is not limited to their individual contribution amounts. PG&E Corporation and the Utility will assess the Wildfire Fund asset for impairment in the event that a participating utility's electrical equipment is found to be the substantial cause of a catastrophic wildfire. Timing of any such impairment could lag as the emergence of sufficient cause and claims information can take many quarters and could be limited to public disclosure of the participating electric utility, if ignition were to occur outside the Utility's service territory. There were fires in the Utility's and other participating utilities' service territories in 2020 for which the cause is currently unknown and which may in the future be determined to be covered by the Wildfire Fund. At December 31, 2020, there were no such known events requiring a reduction of the Wildfire Fund asset nor have there been any claims or withdrawals by the participating utilities against the Wildfire Fund.

Other Accounting Policies

For other accounting policies impacting PG&E Corporation's and the Utility's Consolidated Financial Statements, see "Income Taxes" in Note 9, "Derivatives" in Note 10, "Fair Value Measurements" in Note 11, and "Contingencies and Commitments" in Notes 14 and 15 herein.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2020 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
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Beginning balance	\$ (22)	\$ 17	\$ (5)
Other comprehensive income before reclassifications:			
Unrecognized net actuarial gain (loss) (net of taxes of \$162 and \$66, respectively)	(417)	170	(247)
Regulatory account transfer (net of taxes of \$155 and \$66, respectively)	400	(170)	230
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of \$2 and \$4, respectively) ⁽¹⁾	(4)	10	6
Amortization of net actuarial (gain) loss (net of taxes of \$1 and \$6, respectively) ⁽¹⁾	2	(15)	(13)
Regulatory account transfer (net of taxes of \$1 and \$2, respectively) ⁽¹⁾	2	5	7
Net current period other comprehensive loss	(17)	—	(17)
Ending balance	\$ (39)	\$ 17	\$ (22)

⁽¹⁾ These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 12 below for additional details.)

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2019 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
Beginning balance	\$ (21)	\$ 17	\$ (4)
Other comprehensive income before reclassifications:			
Unrecognized net actuarial loss (net of taxes of \$24 and \$88, respectively)	61	227	288
Regulatory account transfer (net of taxes of \$24 and \$88, respectively)	(62)	(227)	(289)
Amounts reclassified from other comprehensive income:			
Amortization of prior service cost (net of taxes of \$2 and \$4, respectively) ⁽¹⁾	(4)	10	6
Amortization of net actuarial loss (net of taxes of \$1 and \$1, respectively) ⁽¹⁾	2	(2)	—
Regulatory account transfer (net of taxes of \$1 and \$3, respectively) ⁽¹⁾	2	(8)	(6)
Net current period other comprehensive loss	(1)	—	(1)
Ending balance	\$ (22)	\$ 17	\$ (5)

⁽¹⁾ These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 12 below for additional details.)

Recognition of Lease Assets and Liabilities

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A lease exists when an arrangement allows the lessee to control the use of an identified asset for a stated period in exchange for payments. This determination is made at inception of the arrangement. All leases must be recognized as a ROU asset and a lease liability on the balance sheet of the lessee. The ROU asset reflects the lessee's right to use the underlying asset for the lease term and the lease liability reflects the obligation to make the lease payments. PG&E Corporation and the Utility have elected not to separate lease and non-lease components.

The Utility estimates the ROU assets and lease liabilities at net present value using its incremental secured borrowing rates, unless the implicit discount rate in the leasing arrangement can be ascertained. The incremental secured borrowing rate is based on observed market data and other information available at the lease commencement date. The ROU assets and lease liabilities only include the fixed lease payments for arrangements with terms greater than 12 months. These amounts are presented within the supplemental disclosures of noncash activities on the Consolidated Statement of Cash Flows. Renewal and termination options only impact the lease term if it is reasonably certain that they will be exercised. PG&E Corporation recognizes lease expense on a straight-line basis over the lease term. The Utility recognizes lease expense in conformity with ratemaking.

Operating leases are included in operating lease ROU assets and current and noncurrent operating lease liabilities on the Consolidated Balance Sheets. Financing leases are included in property, plant, and equipment, other current liabilities, and other noncurrent liabilities on the Consolidated Balance Sheets. Financing leases were immaterial for the years ended December 31, 2020 and 2019.

For the years ended December 31, 2020 and 2019, the Utility made total cash payments, including fixed and variable, of \$2.5 billion and \$2.4 billion, respectively, for operating leases which are presented within operating activities on the Consolidated Statement of Cash Flows. The fixed cash payments for the principal portion of the financing lease liabilities are immaterial and continue to be included within financing activities on the Consolidated Statement of Cash Flows. Any variable lease payments for financing leases are included in operating activities on the Consolidated Statement of Cash Flows.

The majority of the Utility's ROU assets and lease liabilities relate to various power purchase agreements. These power purchase agreements primarily consist of generation plants leased to meet customer demand plus applicable reserve margins. Operating lease variable costs include amounts from renewable energy power purchase agreements where payments are based on certain contingent external factors such as wind, hydro, solar, biogas, and biomass power generation. See "Third-Party Power Purchase Agreements" in Note 15 below. PG&E Corporation and the Utility have also recorded ROU assets and lease liabilities related to property and land arrangements.

At December 31, 2020 and 2019, the Utility's operating leases had a weighted average remaining lease term of 5.7 years and 5.9 years and a weighted average discount rate of 6.2% and 6.2%, respectively.

The following table shows the lease expense recognized for the fixed and variable component of the Utility's lease obligations:

(in millions)	Year Ended December 31,	
	2020	2019
Operating lease fixed cost	\$ 679	\$ 686
Operating lease variable cost	1,852	1,778
Total operating lease costs	\$ 2,531	\$ 2,464

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At December 31, 2020, the Utility's future expected operating lease payments were as follows:

(in millions)	December 31, 2020
2021	\$ 624
2022	550
2023	257
2024	98
2025	91
Thereafter	513
Total lease payments	2,133
Less imputed interest	(397)
Total	\$ 1,736

Recently Adopted Accounting Standards

Intangibles—Goodwill and Other

In August 2018, the FASB issued ASU No. 2018-15, *Intangibles – Goodwill and Other – Internal - Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract*. PG&E Corporation and the Utility adopted the ASU on January 1, 2020. The adoption of this ASU did not have a material impact on the Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses On Financial Instruments*, which provides a model, known as the current expected credit loss model, to estimate the expected lifetime credit loss on financial assets, including trade and other receivables, rather than incurred losses over the remaining life of most financial assets measured at amortized cost. The guidance also requires use of an allowance to record estimated credit losses on available-for-sale debt securities. PG&E Corporation and the Utility adopted the ASU on January 1, 2020.

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PG&E Corporation and the Utility have three categories of financial assets in scope, each with their own associated credit risks. In applying the new guidance, PG&E Corporation and the Utility have incorporated forward-looking data in their estimate of credit loss as follows. Trade receivables are represented by customer accounts receivable and have credit exposure risk related to California unemployment rates. Insurance receivables are related to the liability insurance policies PG&E Corporation and the Utility carry. Insurance receivable risk is related to each insurance carrier's risk of defaulting on their individual policies. Lastly, available-for-sale debt securities requires each company to determine if a decline in fair value is below amortized costs basis, or, impaired. Furthermore, if an impairment exists on available-for-sale debt securities, PG&E Corporation and the Utility will examine if there is an intent to sell, if it is more likely than not a requirement to sell prior to recovery, and if a portion of the unrealized loss is a result of credit loss. As of December 31, 2020, expected credit losses of \$150 million were recorded in Operating and maintenance expense on the Consolidated Statements of Income for credit losses associated with trade and other receivables. Of these amounts recorded at December 31, 2020, \$76 million and \$10 million were deemed probable of recovery and deferred to the CPPMA and a FERC regulatory asset, respectively.

Reference Rate Reform

In March 2020, the FASB issued ASU No. 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*, which provides optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. PG&E Corporation and the Utility adopted this ASU on April 1, 2020 and elected the optional amendments for contract modifications prospectively. There was no material impact to PG&E Corporation's or the Utility's Consolidated Financial Statements resulting from the adoption of this ASU.

Defined Benefit Plans

In August 2018, the FASB issued ASU No. 2018-14, *Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans*, which amends the existing guidance relating to the disclosure requirements for defined benefit plans. PG&E Corporation and the Utility adopted the ASU as of December 31, 2020. The adoption of ASU 2018-14 resulted in elimination of the disclosures of (i) the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost over the next fiscal year and (ii) the effects of a one-percentage-point change in assumed health care cost trend rates on the (1) aggregate of the service and interest cost components of net periodic benefit costs and (2) benefit obligation for postretirement health care benefits. Additionally, the adoption of this ASU resulted in new disclosures of (i) the weighted-average interest crediting rates for cash balance plans and (ii) an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period. These amendments have been applied on a retrospective basis to all periods presented. See Note 12 below for further discussion of PG&E Corporation's and the Utility's defined benefit pension plans.

Accounting Standards Issued But Not Yet Adopted

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, which amends the existing guidance to reduce complexity relating to Income Tax disclosures. This ASU became effective for PG&E Corporation and the Utility on January 1, 2021 and will not have a material impact on the Consolidated Financial Statements and the related disclosures.

Debt

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In August 2020, the FASB issued ASU No. 2020-06, *Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, which simplifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2022, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

NOTE 4: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31,		Recovery Period
	2020	2019	
Pension benefits (1)	\$ 2,245	\$ 1,823	Indefinitely
Environmental compliance costs	1,112	1,062	32 years
Utility retained generation (2)	181	228	6 years
Price risk management	204	124	19 years
Unamortized loss, net of gain, on reacquired debt	49	63	23 years
Catastrophic event memorandum account (3)	842	656	1 - 3 years
Wildfire expense memorandum account (4)	400	423	1 - 3 years
Fire hazard prevention memorandum account (5)	137	259	1 - 3 years
Fire risk mitigation memorandum account (6)	66	95	1 - 3 years
Wildfire mitigation plan memorandum account (7)	390	558	1 - 3 years
Deferred income taxes (8)	908	252	51 years
Insurance premium costs (9)	294	—	1 - 4 years
Wildfire mitigation balancing account (10)	156	—	1 - 3 years
General rate case memorandum accounts (11)	376	—	1 - 2 years
Vegetation management balancing account (12)	592	—	1 - 3 years
COVID-19 pandemic protection memorandum accounts (13)	84	—	TBD years
Other	942	523	Various
Total long-term regulatory assets	\$ 8,978	\$ 6,066	

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- (1) Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the Utility expects to continuously recover pension benefits.
- (2) In connection with the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's 2001 proceeding under Chapter 11, the CPUC authorized the Utility to recover \$1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.
- (3) Includes costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities. As of December 31, 2020, \$49 million in COVID-19 related costs was recorded to CEMA regulatory assets. Recovery of CEMA costs is subject to CPUC review and approval.
- (4) Includes incremental wildfire liability insurance premium costs the CPUC approved for tracking in June 2018 for the period July 26, 2017 through December 31, 2019. Recovery of WEMA costs is subject to CPUC review and approval.
- (5) Includes costs associated with the implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities that have not been previously authorized in another proceeding. Recovery of FHPMA costs is subject to CPUC review and approval.
- (6) Includes costs associated with the 2019 WMP for the period January 1, 2019 through June 4, 2019. Recovery of FRMMA costs is subject to CPUC review and approval.
- (7) Includes costs associated with the 2019 WMP for the period June 5, 2019 through December 31, 2019 and the 2020 WMP for the period of January 1, 2020 through December 31, 2020. Recovery of WMPMA costs is subject to CPUC review and approval.
- (8) Represents cumulative differences between amounts recognized for ratemaking purposes and expense recognized in accordance with GAAP.
- (9) Represents non-current excess liability insurance premium costs recorded to RTBA and Adjustment Mechanism for Costs Determined in Other Proceedings, as authorized in the 2020 GRC and 2019 GT&S rate cases, respectively.
- (10) Includes costs associated with certain wildfire mitigation activities for the period January 1, 2020 through December 31, 2020. Long-term balance represents costs above 115% of adopted revenue requirements, which are subject to CPUC review and approval.
- (11) The General Rate Case Memorandum Accounts record the difference between the gas and electric revenue requirements in effect on January 1, 2020 and through the date of the final 2020 GRC decision as authorized by the CPUC in December 2020. These amounts will be recovered in rates over 17 months, beginning March 1, 2021.
- (12) The 2020 GRC Decision authorized the Utility to modify the existing one-way VMBA Expense Balancing Account to a two-way balancing account to track the difference between actual and adopted expenses resulting from its routine vegetation management and enhanced vegetation management activities previously recorded in the FRMMA/WMPMA, and tree mortality and fire risk reduction work previously recorded in CEMA. Recovery of VMBA costs above 120% of adopted revenue requirements is subject to CPUC review and approval.
- (13) On April 16, 2020, the CPUC passed a resolution that established the CPPMA to recover costs associated with customer protections, including higher uncollectible costs related to a moratorium on electric and gas service disconnections for residential and small business customers. The CPPMA applies only to residential and small business customers and was approved on July 27, 2020 with an effective date of March 4, 2020. As of December 31, 2020, the Utility had recorded an aggregate under-collection of \$76 million, representing incremental bad debt expense over what was collected in rates for the period the CPPMA is in effect. The remaining \$8 million is associated with program costs and higher accounts receivable financing costs. Recovery of CPPMA costs is subject to CPUC review and approval.

In general, regulatory assets represent the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recognized in accordance with GAAP. Additionally, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return on its regulatory assets for retained generation, and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

Balance at December 31,

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(in millions)	2020	2019
Cost of removal obligations (1)	\$ 6,905	\$ 6,456
Recoveries in excess of AROs (2)	458	393
Public purpose programs (3)	948	817
Employee benefit plans (4)	995	750
Other	1,118	854
Total long-term regulatory liabilities	\$ 10,424	\$ 9,270

(1) Represents the cumulative differences between the recorded costs to remove assets and amounts collected in rates for expected costs to remove assets.

(2) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on these nuclear decommissioning trust investments. (See Note 11 below.)

(3) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

(4) Represents cumulative differences between incurred costs and amounts collected in rates for Post-Retirement Medical, Post-Retirement Life and Long-Term Disability Plans.

Regulatory Balancing Accounts

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a period exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are comprised of the following:

(in millions)	Receivable Balance at December 31,	
	2020	2019
Electric transmission	\$ —	\$ 9
Gas distribution and transmission	102	363
Energy procurement	413	901
Public purpose programs	292	209
Fire hazard prevention memorandum account	121	—
Fire risk mitigation memorandum account	33	—
Wildfire mitigation plan memorandum account		

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	161	—
Wildfire mitigation balancing account	27	—
General rate case memorandum accounts	313	—
Vegetation management balancing account	115	—
Insurance premium costs	135	—
Other	289	632
Total regulatory balancing accounts receivable	\$ 2,001	\$ 2,114

(in millions)	Payable Balance at December 31,	
	2020	2019
Electric distribution	\$ 55	\$ 31
Electric transmission	267	119
Gas distribution and transmission	76	45
Energy procurement	158	649
Public purpose programs	410	559
Other	279	394
Total regulatory balancing accounts payable	\$ 1,245	\$ 1,797

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. The electric transmission accounts track recovery of costs related to the transmission of electricity approved in the FERC TO rate cases. The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and the GT&S rate case. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency. The FHPMA tracks costs that protect the public from potential fire hazards. The FRMMA and WMPMA balances track costs that are recoverable within 12 months as requested in the 2020 WMCE application. The WMBA tracks costs associated with wildfire mitigation revenue requirement activities. The general rate case memorandum accounts track the difference between the revenue requirements in effect on January 1, 2020 and the revenue requirements authorized by the CPUC in the 2020 GRC Decision in December 2020. The VMBA tracks routine and enhanced vegetation management activities. The insurance premium costs track the current portion of incremental excess liability insurance costs recorded to RTBA and adjustment mechanism for costs determined in other proceedings, as authorized in the 2020 GRC and 2019 GT&S rate cases, respectively. In addition to insurance premium costs recorded in Regulatory balancing accounts receivable and in Long-term regulatory assets above, at December 31, 2020, there was \$93 million in insurance premium costs recorded in Current regulatory assets.

NOTE 5: DEBT

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Debtor-In-Possession Facilities

In connection with the Chapter 11 Cases, PG&E Corporation and the Utility entered into the DIP Credit Agreement, among the Utility, as borrower, PG&E Corporation, as guarantor, JPM, as administrative agent, Citibank, N.A., as collateral agent, and the lenders and issuing banks party thereto.

On July 1, 2020, the DIP Facilities were repaid in full and all commitments thereunder were terminated in connection with emergence from Chapter 11.

Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings and availability under their credit facilities at December 31, 2020:

(in millions)	Termination Date	Facility Limit	Borrowings Outstanding	Letters of Credit Outstanding	Facility Availability
			(1		
Utility revolving credit facility	July 2023	\$ 3,500	\$ 605	\$ 1,020	\$ 1,875
Utility term loan credit facility	Various ⁽²⁾	3,000	3,000	—	—
Utility receivables securitization program	October 2022	1,000	1,000	—	—
PG&E Corporation revolving credit facility	July 2023	500	—	—	500
Total credit facilities		\$ 8,000	\$ 4,605	\$ 1,020	\$ 2,375

(1) Includes a \$1.5 billion letter of credit sublimit.

(2) This includes a \$1.5 billion term loan credit facility with a maturity date of June 30, 2021 and a \$1.5 billion term loan credit facility with a maturity date of January 1, 2022.

Utility

Utility Revolving Credit Facility

On July 1, 2020, the Utility entered into a \$3.5 billion revolving credit agreement (the "Utility Revolving Credit Agreement") with JPM, and Citibank, N.A. as co-administrative agents, and Citibank, N.A., as designated agent. The Utility Revolving Credit Agreement has a maturity date three years after the Effective Date, subject to two one-year extensions options.

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Borrowings under the Utility Revolving Credit Agreement bear interest based on the Utility's election of either (1) LIBOR plus an applicable margin of 1.375% to 2.50% based on the Utility's credit rating or (2) the base rate plus an applicable margin of 0.375% to 1.50% based on the Utility's credit rating. In addition to interest on outstanding principal under the Utility Revolving Credit Agreement, the Utility is required to pay a commitment fee to the lenders in respect of the unutilized commitments thereunder, ranging from 0.25% to 0.50% per annum depending on the Utility's credit rating. The Utility Revolving Credit Agreement has a maximum letter of credit sublimit equal to \$1.5 billion. The Utility may also pay customary letter of credit fees based on letters of credit issued under the Utility Revolving Credit Agreement.

The Utility's obligations under the Utility Revolving Credit Agreement are secured by the issuance of a first mortgage bond, issued pursuant to the Utility's mortgage indenture, secured by a first lien on substantially all of the Utility's real property and certain tangible personal property related to its facilities, subject to certain exceptions, and which rank *pari passu* with the Utility's other first mortgage bonds.

The Utility Revolving Credit Agreement includes usual and customary provisions for revolving credit agreements of this type, including covenants limiting, with certain exceptions, (1) liens, (2) indebtedness, (3) sale and leaseback transactions, and (4) fundamental changes. In addition, the Utility Revolving Credit Agreement requires that the Utility maintain a ratio of total consolidated debt to consolidated capitalization of no greater than 65% as of the end of each fiscal quarter. As of December 31, 2020, the Utility was in compliance with this covenant.

In the event of a default by the Utility under the Utility Revolving Credit Agreement, including cross-defaults relating to specified other debt of the Utility or any of its significant subsidiaries in excess of \$200 million, the designated agent may, with the consent of the required lenders (or shall upon the request of the required lenders), declare the amounts outstanding under the Utility Revolving Credit Agreement, including all accrued interest, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the amounts outstanding under the Utility Revolving Credit Agreement become payable immediately.

The Utility may voluntarily repay outstanding loans under the Utility Revolving Credit Agreement at any time without premium or penalty, other than customary "breakage" costs with respect to eurodollar rate loans. Any voluntary prepayments made by the Utility will not reduce the commitments under the Utility Revolving Credit Agreement.

Utility Term Loan Credit Facility

On July 1, 2020, the Utility obtained a \$3.0 billion secured term loan under a term loan credit agreement (the "Utility Term Loan Credit Agreement") with JPM, as administrative agent. The credit facilities under the Utility Term Loan Credit Agreement consist of a \$1.5 billion 364-day term loan facility (the "Utility 364-Day Term Loan Facility") and a \$1.5 billion 18-month term loan facility (the "Utility 18-Month Term Loan Facility"). The maturity date for the 364-Day Term Loan Facility is June 30, 2021 and the maturity date for the Utility 18-Month Term Loan Facility is January 1, 2022. The Utility borrowed the entire amount of the Utility 364-Day Term Loan Facility and the Utility 18-Month Term Loan Facility on July 1, 2020. The proceeds were used to fund, in part, transactions contemplated under the Plan.

Borrowings under the Utility Term Loan Credit Agreement bear interest based on the Utility's election of either (1) LIBOR plus an applicable margin of 2.00% with respect to the Utility 364-Day Term Loan Facility and 2.25% with respect to the Utility 18-Month Term Loan Facility, or (2) the base rate plus an applicable margin of 1.00% with respect to the Utility 364-Day Term Loan Facility and 1.25% with respect to the Utility 18-Month Term Loan Facility.

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The Utility's obligations under the Utility Term Loan Credit Agreement are secured by the issuance of first mortgage bonds, issued pursuant to the Utility's mortgage indenture, secured by a first lien on substantially all of the Utility's real property and certain tangible personal property related to its facilities, subject to certain exceptions, and which rank *pari passu* with the Utility's other first mortgage bonds.

The Utility Term Loan Credit Agreement includes usual and customary provisions for term loan agreements of this type, including covenants limiting, with certain exceptions, (1) liens, (2) indebtedness, (3) sale and leaseback transactions, (4) fundamental changes, (5) entering into swap agreements and (6) modifications to the Utility's mortgage indenture. In addition, the Utility Term Loan Credit Agreement requires that the Utility maintain a ratio of total consolidated debt to consolidated capitalization of no greater than 65% as of the end of each fiscal quarter. As of December 31, 2020, the Utility was in compliance with this covenant.

In the event of a default by the Utility under the Utility Term Loan Credit Agreement, including cross-defaults relating to specified other debt of the Utility or any of its significant subsidiaries in excess of \$200 million, the administrative agent may, with the consent of the required lenders (or upon the request of the required lenders, shall), declare the amounts outstanding under the Utility Term Loan Credit Agreement, including all accrued interest, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the amounts outstanding under the Utility Term Loan Credit Agreement become payable immediately.

The Utility is required to prepay outstanding term loans under the Utility Term Loan Credit Agreement (with all outstanding term loans made under the Utility 364-Day Term Loan Facility being paid first), subject to certain exceptions, with 100% of the net cash proceeds of certain securitization transactions. The Utility may voluntarily repay outstanding loans under the Utility Term Loan Credit Agreement at any time without premium or penalty, other than customary "breakage" costs with respect to eurodollar rate loans.

Receivables Securitization Program

On October 5, 2020, the Utility, in its individual capacity and in its capacity as initial servicer, entered into an accounts receivable securitization program (the "Receivables Securitization Program"), providing for the sale of a portion of the Utility's accounts receivable to the SPV, a limited liability company wholly owned by the Utility. Pursuant to the Receivables Securitization Program, the Utility sells certain of its receivables and certain related rights to payment and obligations of the Utility with respect to such receivables and certain other related rights to the SPV, which, in turn, obtains loans secured by the receivables from financial institutions (the "Lenders"). The Utility has pledged to the Lenders 100% of the equity interests in the SPV as security for the repayment of the loans. The aggregate principal amount of the loans made by the Lenders cannot exceed \$1.0 billion outstanding at any time.

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The loans under the Receivables Securitization Program bear interest based on a spread over LIBOR dependent on the tranche period thereto and any breakage fees accrued. The receivables financing agreement contains customary LIBOR benchmark replacement language giving the administrative agent, with consent from the SPV as to the successor rate, the right to determine such successor rate. The Receivables Securitization Program contains certain customary representations and warranties and affirmative and negative covenants, including as to the eligibility of the receivables being sold by the Utility and securing the loans made by the Lenders, as well as customary reserve requirements, Receivables Securitization Program termination events, and servicer defaults. The Receivables Securitization Program termination events permit the Lenders to terminate the agreement upon the occurrence of certain specified events, including failure by the SPV to pay amounts when due, certain defaults on indebtedness under the Utility's credit facility, certain judgments, a change of control, certain events negatively affecting the overall credit quality of transferred receivables and bankruptcy and insolvency events.

The Receivables Securitization Program is scheduled to terminate on October 5, 2022, unless extended or earlier terminated, at which time no further advances will be available and the obligations thereunder must be repaid in full no later than (i) the date that is 180 days following such date or (ii) such earlier date on which the loans under the program become due and payable.

In general, the proceeds from the sale of the accounts receivable are used by the SPV to pay the purchase price for accounts receivables it acquires from the Utility and may be used to fund capital expenditures, repay borrowings on the Utility Revolving Credit Facility, satisfy maturing debt obligations, as well as fund working capital needs and other approved uses.

Although the SPV is a wholly owned consolidated subsidiary of the Utility, the SPV is legally separate from the Utility. The assets of the SPV (including the accounts receivables) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivables are not legally assets of the Utility or PG&E Corporation. The Receivables Securitization Program is accounted for as a secured financing. The pledged receivables and the corresponding debt are included in Accounts receivable and Long-term debt, respectively, on the Consolidated Balance Sheets.

At December 31, 2020 the Utility had outstanding borrowings of \$1.0 billion under the Receivables Securitization Program.

PG&E Corporation

On July 1, 2020, PG&E Corporation entered into a \$500 million revolving credit agreement (the "Corporation Revolving Credit Agreement") with JPM, as administrative agent and collateral agent. The Corporation Revolving Credit Agreement has a maturity date three years after the Effective Date, subject to two one-year extensions at the option of PG&E Corporation. The proceeds from the loans under the Corporation Revolving Credit Agreement will be used to finance working capital needs, capital expenditures and other general corporate purposes of PG&E Corporation and its subsidiaries.

Borrowings under the Corporation Revolving Credit Agreement bear interest based on PG&E Corporation's election of either (1) LIBOR plus an applicable margin of 3.00% to 4.25% based on PG&E Corporation's credit rating or (2) the base rate plus an applicable margin of 2.00% to 3.25% based on PG&E Corporation's credit rating. In addition to interest on outstanding principal under the Corporation Revolving Credit Agreement, PG&E Corporation is required to pay a commitment fee to the lenders in respect of the unutilized commitments thereunder, ranging from 0.50% to 0.75% per annum depending on PG&E Corporation's credit rating.

PG&E Corporation's obligations under the Corporation Revolving Credit Agreement are secured by a pledge of PG&E Corporation's ownership interest in 100% of the shares of common stock of the Utility.

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The Corporation Revolving Credit Agreement includes usual and customary provisions for revolving credit agreements of this type, including covenants limiting, with certain exceptions, (1) liens, (2) indebtedness, (3) sale and leaseback transactions, (4) investments, (5) dispositions, (6) changes in the nature of business, (7) transactions with affiliates, (8) burdensome agreements, (9) restricted payments, (10) fundamental changes, (11) use of proceeds, (12) entering into swap agreements and (13) the ability to dispose of common stock of the Utility. In addition, the Corporation Revolving Credit Agreement requires that PG&E Corporation (1) maintain a ratio of total consolidated debt to consolidated capitalization of no greater than 70% as of the end of each fiscal quarter and (2) if revolving loans are outstanding as of the end of a fiscal quarter, a ratio of adjusted cash to fixed charges, as of the end of such fiscal quarter, of at least 150% prior to the date that PG&E Corporation first declares a cash dividend on its common stock and at least 100% thereafter.

In the event of a default by PG&E Corporation under the Corporation Revolving Credit Agreement, including cross-defaults relating to specified other debt of PG&E Corporation or any of its significant subsidiaries in excess of \$200 million, the administrative agent may, with the consent of the required lenders (or upon the request of the required lenders, shall), declare the amounts outstanding under the Corporation Revolving Credit Agreement, including all accrued interest, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the amounts outstanding under the Corporation Revolving Credit Agreement become payable immediately.

PG&E Corporation may voluntarily repay outstanding loans under the Corporation Revolving Credit Agreement at any time without premium or penalty, other than customary "breakage" costs with respect to eurodollar rate loans. Any voluntary repayments made by PG&E Corporation will not reduce the commitments under the Corporation Revolving Credit Agreement.

On the Effective Date, PG&E Corporation repaid and terminated \$300 million of outstanding borrowings under the Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among PG&E Corporation, as borrower, the several lenders party thereto and Bank of America, N.A., as administrative agent.

Other Short-term Borrowings

On November 16, 2020, the Utility completed the sale of \$1.45 billion aggregate principal amount of floating rate first mortgage bonds due November 15, 2021. Proceeds from the sale of the mortgage bonds were used for general corporate purposes, including the repayment of borrowings outstanding under the Receivables Securitization Program and borrowings outstanding under the Utility Revolving Credit Facility.

Long-Term Debt

Utility

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On June 19, 2020, the Utility completed the sale of (i) \$500 million aggregate principal amount of Floating Rate First Mortgage Bonds due June 16, 2022, (ii) \$2.5 billion aggregate principal amount of 1.75% First Mortgage Bonds due June 16, 2022, (iii) \$1.0 billion aggregate principal amount of 2.10% First Mortgage Bonds due August 1, 2027, (iv) \$2.0 billion aggregate principal amount of 2.50% First Mortgage Bonds due February 1, 2031, (v) \$1.0 billion aggregate principal amount of 3.30% First Mortgage Bonds due August 1, 2040, and (vi) \$1.925 billion aggregate principal amount of 3.50% First Mortgage Bonds due August 1, 2050 (collectively, the “Mortgage Bonds”). The proceeds of the Mortgage Bonds were deposited into an account at The Bank of New York Mellon Trust Company, N.A., as Escrow Agent, which proceeds were held by the Escrow Agent as collateral pursuant to an escrow agreement by and between the Escrow Agent and the Utility. On July 1, 2020, the net proceeds were released from escrow and, together with the net proceeds from certain other Plan financing transactions, were used to effectuate the reorganization of the Utility and PG&E Corporation in accordance with the terms and conditions contained in the Plan.

On the Effective Date, pursuant to the Plan, the Utility issued approximately \$11.9 billion of its first mortgage bonds (the “New Mortgage Bonds”) in satisfaction of certain of its pre-petition senior unsecured debt, as described in the table below.

On the Effective Date, pursuant to the Plan, the Utility reinstated approximately \$9.6 billion aggregate principal amount of the Utility Reinstated Senior Notes. On the Effective Date, each series of the Utility Reinstated Senior Notes was collateralized by the Utility’s delivery of a first mortgage bond in a corresponding principal amount to the applicable trustee for the benefit of the holders of the Utility Reinstated Senior Notes.

The Mortgage Bonds, the New Mortgage Bonds and the Utility Reinstated Senior Notes are secured by a first priority lien, subject to permitted liens, on substantially all of the Utility’s real property and certain tangible property related to its facilities. The Mortgage Bonds, the New Mortgage Bonds and the Utility Reinstated Senior Notes are the Utility’s senior obligations and rank equally in right of payment with the Utility’s other existing or future first mortgage bonds issued under the Utility’s mortgage indenture.

On the Effective Date, by operation of the Plan, all outstanding obligations under the Utility Short-Term Senior Notes, the Utility Long-Term Senior Notes and the Utility Funded Debt were cancelled and the applicable agreements governing such obligations were terminated.

In addition, on July 1, 2020, the Utility obtained a \$1.5 billion 18-month secured term loan under the Utility Term Loan Credit Agreement. For more information, see “Credit Facilities” discussion above.

PG&E Corporation

On June 23, 2020, PG&E Corporation obtained a \$2.75 billion secured term loan (the “PG&E Corporation Term Loan”) under a term loan credit agreement (the “Term Loan Agreement”) with JPM, and other lenders from time to time party thereto (collectively, the “Lenders”), JPM, as Administrative Agent and as Collateral Agent. The proceeds of the PG&E Corporation Term Loan were deposited into an account at The Bank of New York Mellon Trust Company, N.A., as Escrow Agent, which proceeds were held by the Escrow Agent as collateral pursuant to an escrow agreement by and among the Collateral Agent, the Escrow Agent, the Administrative Agent and PG&E Corporation and subsequently released from escrow on the Effective Date pursuant to the Plan.

On February 1, 2021, PG&E Corporation entered into a repricing amendment (the “Repricing Amendment”) with the lenders under the Term Loan Credit Agreement pursuant to which, among other things, the applicable interest rate was reduced.

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In accordance with the Term Loan Agreement, PG&E Corporation is required to repay the principal amount outstanding on the PG&E Corporation Term Loan in an amount equal to \$6.875 million on the last business day of each quarter. The PG&E Corporation Term Loan matures on June 23, 2025, unless extended by PG&E Corporation pursuant to the terms of the Term Loan Agreement. The PG&E Corporation Term Loan bears interest based, at PG&E Corporation's election, on (1) LIBOR plus an applicable margin or (2) ABR plus an applicable margin. The original LIBOR floor was 1.0% but was reduced to 0.5% on February 1, 2021 in connection with the Repricing Amendment. The original ABR floor was 2.0% but was similarly reduced to 1.5% on February 1, 2021 in connection with the Repricing Amendment. ABR will equal the highest of the following: the prime rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus 1.0%. The applicable margin for LIBOR loans is 3.0% (reduced from 4.5% on February 1, 2021 in connection with the Repricing Amendment) and the applicable margin for ABR loans is 2.0% (reduced from 3.5% on February 1, 2021 in connection with the Repricing Amendment). PG&E Corporation may prepay the PG&E Corporation Term Loan in whole, at any time, and in part, from time to time, without premium or penalty, other than customary "breakage" costs with respect to eurodollar rate loans; provided, however, that any voluntary prepayment, refinancing or repricing of the PG&E Corporation Term Loan in connection with certain repricing transactions that occur on or prior to August 1, 2021 shall be subject to a prepayment premium of 1.0% of the principal amount of the term loans so prepaid, refinanced or repriced.

The Term Loan Agreement includes usual and customary covenants for loan agreements of this type, including covenants limiting: (1) liens, (2) mergers, (3) sales of all or substantially all of PG&E Corporation's assets, and (4) sale and leaseback transactions. In addition, the Term Loan Agreement requires that PG&E Corporation maintain ownership, either directly or indirectly, through one or more subsidiaries, of at least 100% of the outstanding common stock of the Utility.

In the event of a default by PG&E Corporation under the Term Loan Agreement, including cross-defaults relating to specified other debt of PG&E Corporation or any of its significant subsidiaries in excess of \$200 million, the Administrative Agent may, with the consent of the required Lenders (or upon the request of the required Lenders, shall), declare the amounts outstanding under the Term Loan Agreement, including all accrued interest, payable immediately. For events of default relating to insolvency, bankruptcy or receivership, the amounts outstanding under the Term Loan Agreement become payable immediately.

On the Effective Date, the obligations under the Term Loan Agreement became secured by a pledge of PG&E Corporation's ownership interest in 100% of the shares of common stock of the Utility. On July 1, 2020, the net proceeds from the PG&E Corporation Term Loan were released from escrow and were used to fund, in part, the transactions contemplated under the Plan.

Additionally, on June 23, 2020, PG&E Corporation completed the sale of (i) \$1.0 billion aggregate principal amount of 5.00% Senior Secured Notes due July 1, 2028 (the "2028 Notes") and (ii) \$1.0 billion aggregate principal amount of 5.25% Senior Secured Notes due July 1, 2030 (the "2030 Notes," and together with the 2028 Notes, the "Notes"). The proceeds of the Notes were initially deposited into an account at The Bank of New York Mellon Trust Company, N.A., as Escrow Agent, which proceeds were held by the Escrow Agent as collateral pursuant to an escrow agreement by and among the Escrow Agent and PG&E Corporation. Prior to July 1, 2023, in the case of the 2028 Notes, and prior to July 1, 2025, in the case of the 2030 Notes, (i) PG&E Corporation may redeem all or part of the Notes of the applicable series, on any one or more occasions at a redemption price equal to 100% of the principal amount of Notes of such series to be redeemed, plus a "make-whole" premium, plus accrued and unpaid interest, if any, to, but not including, the redemption date or (ii) PG&E Corporation may redeem up to 40% of the aggregate principal amount of the Notes of the applicable series on any one or more occasions at certain specified redemption prices with the net cash proceeds from certain equity offerings. On or after July 1, 2023, in the case of the 2028 Notes, and July 1, 2025, in the case of the 2030 Notes, PG&E Corporation may redeem the Notes of a series at certain specified redemption prices, plus accrued and unpaid interest thereon, if any, to but not including, the applicable redemption date.

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On July 1, 2020, the net proceeds from the sale of the Notes were released from escrow and, together with the net proceeds from certain other Plan financing transactions, were used to effectuate the reorganization of PG&E Corporation and the Utility in accordance with the terms and conditions contained in the Plan. The Notes are secured by a pledge of PG&E Corporation's ownership interest in 100% of the shares of common stock of the Utility.

On the Effective Date, PG&E Corporation repaid and terminated \$350 million of borrowings, plus interest, fees and other expenses arising under or in connection with the Term Loan Agreement, dated as of April 16, 2018, among PG&E Corporation, as borrower, the several lenders party thereto and Mizuho Bank Ltd., as administrative agent.

The following table summarizes PG&E Corporation's and the Utility's long-term debt:

(in millions)	Contractual Interest Rates (3)	Balance at		Treatment under Plan on the Effective Date (1)
		December 31, 2020	December 31, 2019	
Pre-Petition Debt (2)				
PG&E Corporation				
Borrowings under Pre-Petition Credit Facility				
PG&E Corporation Revolving Credit Facilities - Stated Maturity: 2022	variable rate (4)	\$ —	\$ 300	Repaid in cash (14)
Other borrowings				
Term Loan - Stated Maturity: 2020	variable rate (5)	—	350	Repaid in cash (14)
Total PG&E Corporation Pre-Petition Long-Term Debt		—	650	
Utility				
Senior Notes - Stated Maturity:				
2020 through 2022	2.45% to 4.25%	—	1,750	Exchanged (15)
2023 through 2028	2.95% to 4.65%	—	5,025	Reinstated (16)
2034 through 2040	5.40% to 6.35%	—	5,700	Exchanged (17)
2041 through 2042	3.75% to 4.50%	—	1,000	Reinstated (16)
2043	5.13%	—	500	Exchanged (17)
2043 through 2047	3.95% to 4.75%	—	3,550	Reinstated (16)
Total Pre-Petition Senior Notes		—	17,525	
Pollution Control Bonds - Stated Maturity:				
Series 2008 F and 2010 E, due 2026	1.75%	—	100	Repaid in cash (14)
Series 2009 A-B, due 2026	variable rate (6)	—	149	Exchanged (18)

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Series 1996 C, E, F, 1997 B due 2026	variable rate (7)	—	614	Exchanged (18)
Total Pre-Petition Pollution Control Bonds		—	863	

Borrowings under Pre-Petition Credit Facilities

Utility Revolving Credit Facilities - Stated Maturity: 2022	variable rate (8)	—	2,888	Exchanged (18)
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Other borrowings:

Term Loan - Stated Maturity: 2019	variable rate (9)	—	250	Exchanged (18)
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Total Borrowings under Pre-Petition Credit Facility

		—	3,138	
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Total Utility Pre-Petition Debt

		—	21,526	
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Total PG&E Corporation Consolidated Pre-Petition

Debt		\$ —	\$ 22,176	
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New Long-Term Debt

PG&E Corporation

Term Loan - Stated Maturity: 2025	variable rate (10)	\$ 2,709	\$ —
Senior Secured Notes due 2028	5.00%	1,000	—
Senior Secured Notes due 2030	5.25%	1,000	—
Unamortized discount, net of premium and debt issuance costs		(85)	—
Total PG&E Corporation New Long-Term Debt		4,624	—

Utility

Pre-Petition Senior Notes Reinstated as First Mortgage Bonds - Stated Maturity:

2023 through 2028	2.95% to 4.65%	5,025	—
2041 through 2042	3.75% to 4.50%	1,000	—
2043 through 2047	3.95% to 4.75%	3,550	—
Unamortized discount, net of premium and debt issuance costs		—	—
Total Utility Reinstated New Long-Term Debt		9,575	—

Pre-Petition Debt Exchanged for First Mortgage Bonds - Stated Maturity:

2025	3.45%	875	—
2026	3.15%	1,951	—
2028	3.75%	875	—

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2030	4.55%	3,100	—
2040	4.50%	1,951	—
2050	4.95%	3,100	—
Unamortized discount, net of premium and debt issuance costs		(98)	—
Total Utility Exchanged New Long-Term Debt		11,754	—
New First Mortgage Bonds - Stated Maturity:			
2022	variable rate ⁽¹¹⁾	500	—
2022	1.75%	2,500	—
2027	2.10%	1,000	—
2031	2.50%	2,000	—
2040	3.30%	1,000	—
2050	3.50%	1,925	—
Unamortized discount, net of premium and debt issuance costs		(84)	—
Total Utility New First Mortgage Bonds		8,841	—
Credit Facilities - Stated Maturity: 2022			
Receivables securitization program	variable rate ⁽¹²⁾	1,000	—
18-month Term Loan	variable rate ⁽¹³⁾	1,500	—
Unamortized discount, net of premium and debt issuance costs		(6)	—
Total Utility New Long-Term Debt		32,664	—
Total PG&E Corporation Consolidated New Long-Term Debt		\$ 37,288	\$ —

(1) The treatments of pre-petition debt under the Plan, as described in this column, relate only to the treatment of principal amounts and not pre-petition or post-petition interest. See “Plan of Reorganization and Restructuring Support Agreements” in Note 2.

(2) As of December 31, 2019, pre-petition debt was reported at the amounts expected to be allowed by the Bankruptcy Court.

(3) The contractual interest rates for pre-petition debt and new debt are presented as of December 31, 2019 and 2020, respectively.

(4) At December 31, 2019, the contractual LIBOR-based interest rate on loans was 3.24%.

(5) At December 31, 2019, the contractual LIBOR-based interest rate on the term loan was 2.96%.

(6) At December 31, 2019, the contractual interest rate on the letter of credit facilities supporting these bonds was 7.95%.

(7) At December 31, 2019, the contractual interest rate on the letter of credit facilities supporting these bonds ranged from 7.95% to 8.08%.

(8) At December 31, 2019, the contractual LIBOR-based interest rate on the loans was 3.04%.

(9) At December 31, 2019, the contractual LIBOR-based interest rate on the term loan was 2.36%.

(10) At December 31, 2020, the contractual LIBOR-based interest rate on the term loan was 5.50%.

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- (11) At December 31, 2020, the contractual LIBOR-based interest rate on the first mortgage bonds was 1.70%.
- (12) At December 31, 2020, the contractual LIBOR-based interest rate on the receivables securitization program was 1.57%.
- (13) At December 31, 2020, the contractual LIBOR-based interest rate on the term loan was 2.44%.
- (14) In accordance with the Plan, these borrowings were repaid in cash on July 1, 2020.
- (15) In accordance with the Plan, on July 1, 2020, the Utility issued \$875 million aggregate principal amount of 3.45% first mortgage bonds due 2025 and \$875 million aggregate principal amount of 3.75% first mortgage bonds due 2028, in satisfaction of these Senior Notes. See “Pre-Petition Debt Exchanged for First Mortgage Bonds” in the table above.
- (16) In accordance with the Plan, these Senior Notes were reinstated (and secured by First Mortgage Bonds) on July 1, 2020. See “Pre-Petition Senior Notes Reinstated (and secured by First Mortgage Bonds)” in the table above.
- (17) In accordance with the Plan, on July 1, 2020, the Utility issued \$3.1 billion aggregate principal amount of 4.55% first mortgage bonds due 2030 and \$3.1 billion aggregate principal amount of 4.95% first mortgage bonds due 2050, in satisfaction of these Senior Notes. See “Pre-Petition Debt Exchanged for First Mortgage Bonds” in the table above.
- (18) In accordance with the Plan, on July 1, 2020, the Utility issued \$1.95 billion aggregate principal amount of 3.15% first mortgage bonds due 2026 and \$1.95 billion aggregate principal amount of 4.50% first mortgage bonds due 2040, in satisfaction of these pre-petition liabilities. See “Pre-Petition Debt Exchanged for First Mortgage Bonds” in the table above.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility’s Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sales agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, the Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

In accordance with the Plan, on July 1, 2020, the Utility repaid Series 2008 F and 2010 E and exchanged Series 2009 A-B, Series 1996 C, E, F, and 1997 B for first mortgage bonds.

Contractual Repayment Schedule

PG&E Corporation’s and the Utility’s combined stated long-term debt principal repayment amounts at December 31, 2020 are reflected in the table below:

(in millions,

except interest rates)	2021	2022	2023	2024	2025	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	— %	— %	— %	— %	— %	5.13 %	5.13 %
Fixed rate obligations	— %	— %	— %	— %	— %	\$2,000	\$2,000
Variable interest rate as of December 31, 2020	5.50 %	5.50 %	5.50 %	5.50 %	5.50 %	— %	5.50 %

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Variable rate obligations	\$ 28	\$ 28	\$ 28	\$ 28	\$ 2,625	\$ —	\$ 2,737
Utility							
Average fixed interest rate	— %	1.75 %	3.83 %	3.60 %	3.47 %	3.87 %	3.66 %
Fixed rate obligations	\$ —	\$ 2,500	\$ 1,175	\$ 800	\$ 1,475	\$ 23,902	\$ 29,852
Variable interest rate as of December 31, 2020	— %	various (1)	— %	— %	— %	— %	various (1)
Variable rate obligations	\$ —	\$ 3,000	\$ —	\$ —	\$ —	\$ —	\$ 3,000
Total consolidated debt	\$ 28	\$ 5,528	\$ 1,203	\$ 828	\$ 4,100	\$ 25,902	\$ 37,589

(1) At December 31, 2020, the average interest rates for the Receivables Securitization Program, the first mortgage bonds due 2022 and the 18-month term loan were 1.57%, 1.70% and 2.44% respectively.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 1,984,678,673 shares of common stock outstanding at December 31, 2020. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2020.

On July 23, 2020, PG&E Corporation sent a notice of termination to the managers of the Amended and Restated Equity Distribution Agreement, dated as of February 17, 2017, effectively terminating the agreement on that date. As of the termination date for this agreement, no amounts were outstanding which required repayment.

Increase in Authorized Capitalization

On June 22, 2020, PG&E Corporation filed Amended Articles of Incorporation with the Secretary of State of California which increased the authorized number of shares of common stock to 3.6 billion and the authorized number of shares of preferred stock to 400 million.

Plan Equity Financings

In connection with emergence from Chapter 11, in July 2020, PG&E Corporation raised an aggregate of \$9.0 billion of gross proceeds through the issuance of common stock and other equity-linked instruments as described below.

PG&E Corporation Investment Agreement

On June 7, 2020, PG&E Corporation entered into an Investment Agreement (the "Investment Agreement") with certain investors (the "Investors") relating to the issuance and sale to the Investors of an aggregate of \$3.25 billion of PG&E Corporation's common stock. Per the Investment Agreement, the price per share was equal to \$9.50 per share, which was the public equity offering price in the Common Stock Offering (as defined below in "Equity Offerings").

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On July 1, 2020, pursuant to the terms of the Investment Agreement, PG&E Corporation issued to the Investors 342.1 million shares of common stock. The Investors and their affiliates have certain customary registration rights with respect to the Shares held by such Investor pursuant to the terms of the Investment Agreement.

Equity Offerings

On June 25, 2020, PG&E Corporation priced (i) the Common Stock Offering of 423.4 million shares of its common stock, and (ii) the concurrent Equity Units Offering of 14.5 million of its Equity Units, for total net proceeds to PG&E Corporation, after deducting the underwriting discounts and before estimated offering expenses payable by the PG&E Corporation, of \$3.97 billion and \$1.19 billion, respectively.

On June 25, 2020, in connection with the Common Stock Offering, PG&E Corporation entered into an underwriting agreement (the "Common Stock Underwriting Agreement") with Goldman Sachs & Co. LLC and J.P. Morgan Securities LLC, as representatives of several underwriters named in the Common Stock Underwriting Agreement (the "Common Stock Underwriters"), pursuant to which PG&E Corporation agreed to issue and sell 423.4 million shares of its common stock to the Common Stock Underwriters. In addition, on June 25, 2020, PG&E Corporation entered into an underwriting agreement (the "Equity Units Underwriting Agreement") with Goldman Sachs & Co. LLC and J.P. Morgan Securities LLC, as representatives of the several underwriters named in the Equity Units Underwriting Agreement (the "Equity Units Underwriters"), pursuant to which PG&E Corporation agreed to issue and sell 14.5 million prepaid forward stock purchase contracts (the "Purchase Contracts") to the Equity Underwriters in order for the Equity Units Underwriters to sell 14.5 million Equity Units.

In connection with the Common Stock Offering and pursuant to the Common Stock Underwriting Agreement, PG&E Corporation granted the underwriters a 30-day over-allotment option to purchase up to an additional 42.3 million shares of common stock. In addition, in connection with the Equity Units Offering and pursuant to the Equity Units Underwriting Agreement, PG&E Corporation also granted the underwriters a 30-day over-allotment option to purchase up to an additional 1.45 million Purchase Contracts to be used by the Equity Units Underwriters to create up to an additional 1.45 million Equity Units (together with the 42.3 million shares of common stock, the "Option Securities").

The Common Stock Offering and the Equity Units Offering closed on July 1, 2020, and PG&E Corporation issued and sold a total of 423.4 million shares of its common stock and 14.5 million Purchase Contracts for total net proceeds of \$5.2 billion. On July 24, 2020, the Equity Units Underwriters exercised in full, the over-allotment option in the Equity Units Underwriting Agreement and on August 3, 2020, PG&E Corporation issued and sold 1.45 million Equity Units to the Equity Units Underwriters (the "Additional Units Issuance"). The prepaid forward stock purchase contract portion of the Equity Units issued in the Equity Units Offering and the Additional Units Issuance represents the right of the unitholders to receive, on the settlement date, between 125 million and 153 million shares, and between 12.5 million and 15.3 million shares, respectively, of PG&E Corporation common stock, based on the value of PG&E Corporation common stock over a measurement period specified in the purchase contracts and subject to certain adjustments as provided herein. The settlement date of the purchase contract is August 16, 2023, subject to acceleration or postponement as provided in the purchase contracts. The Common Stock Underwriters did not exercise their option to purchase any additional shares of common stock.

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PG&E Corporation applied accounting standards applicable to prepaid forward contracts to purchase common stock in order to determine the proper balance sheet classification for the Equity Units issued and sold during the three months ended, September 30, 2020. The Equity Units are considered a range forward contract, in that the settlement of common stock shares is based on a range of potential settlement outcomes. PG&E Corporation used various inputs, including stock price volatility, and determined that the potential outcomes are predominantly fixed share settlements. As such, PG&E Corporation does not view the Equity Units as an obligation to issue a variable number of shares and has concluded that the Equity Units meet all conditions for equity classification and do not meet any of the other conditions that would result in asset or liability classification. The Equity Units issued and sold are classified as Common stock on PG&E Corporation's Consolidated Balance Sheet.

Equity Backstop Commitments and Forward Stock Purchase Agreements

See "Equity Financing" in Note 2 above for discussion of the equity backstop commitments which resulted in total net proceeds of \$523 million (of which \$120.5 million were returned to the Backstop Parties pursuant to the Forward Stock Purchase Agreements, as described below).

In connection with the Additional Units Issuance and pursuant to the terms of the Forward Stock Purchase Agreements, on August 3, 2020, PG&E Corporation (i) redeemed a portion of the rights under the Forward Stock Purchase Agreements to receive shares of Common Stock and returned approximately \$120.5 million to the Backstop Parties and (ii) issued and delivered to the Backstop Parties 42.3 million Greenshoe Backstop Shares, representing the unredeemed portion of the Aggregate Greenshoe Backstop Purchase Amount divided by the Settlement Price (without any issuance in respect of fractional shares).

Equity Issuances to the Fire Victim Trust

On the Effective Date, pursuant to the Plan, the Utility entered into the Fire Victim Trust Assignment Agreement, pursuant to which the Utility transferred to the Fire Victim Trust 477 million shares of common stock of PG&E Corporation. As a result of the Additional Units Issuance, on August 3, 2020, PG&E Corporation made an equity contribution of 748,415 shares to the Utility which delivered such additional shares of common stock to the Fire Victim Trust pursuant to an anti-dilution provision in the Fire Victim Trust Assignment Agreement.

Cash Contribution to the Utility Pursuant to the Plan

On the Effective Date, PG&E Corporation made an equity contribution of \$12.9 billion in cash to the Utility, which used the funds to satisfy and discharge certain liabilities of PG&E Corporation and the Utility under the Plan. PG&E Corporation's cash equity contribution was funded by proceeds from the financing transactions described herein.

Ownership Restrictions in PG&E Corporation's Amended Articles

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Under Section 382 of the Internal Revenue Code, if a corporation (or a consolidated group) undergoes an “ownership change,” net operating loss carryforwards and other tax attributes may be subject to certain limitations (which could limit PG&E Corporation or the Utility’s ability to use these deferred tax assets to offset taxable income). In general, an ownership change occurs if the aggregate stock ownership of certain shareholders (generally five percent shareholders, applying certain look-through and aggregation rules) increases by more than 50% over such shareholders’ lowest percentage ownership during the testing period (generally three years). PG&E Corporation’s and the Utility’s Amended Articles limit Transfers (as defined in the Amended Articles) that increase a person’s or entity’s (including certain groups of persons) ownership of PG&E Corporation’s equity securities to more than 4.75% prior to the Restriction Release Date without approval by the Board of Directors. The calculation of the percentage ownership may differ depending on whether the Fire Victim Trust is treated as a qualified settlement trust or grantor trust.

As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change and consequently, its net operating loss carryforwards and other tax attributes are not limited by Section 382 of the Internal Revenue Code.

In 2019, \$6.75 billion of the liability to be paid to the Fire Victim Trust in PG&E Corporation’s common stock was accrued by the Utility. Because the corresponding tax deduction generally occurs no earlier than payment, the Utility established a deferred tax asset for the accrual in 2019. On July 1, 2020, the Utility issued to the Fire Victim Trust 477 million shares of PG&E Corporation’s common stock. The shares transferred to the Fire Victim Trust were valued at \$4.53 billion on the date of transfer, \$2.2 billion less than the \$6.75 billion that had been accrued as a liability in the Condensed Consolidated Financial Statements. Therefore, in the quarter ended June 30, 2020, the Utility recorded a charge of \$619 million to adjust the measurement of the deferred tax asset to reflect the tax-effected difference between the accrual of \$6.75 billion and the tax deduction of \$4.53 billion for the transfer of PG&E Corporation’s shares to the Fire Victim Trust.

In addition, the tax deduction recorded reflects PG&E Corporation’s conclusion as of December 31, 2020 that it is more likely than not that the Fire Victim Trust will be treated as a “qualified settlement fund” for U.S. federal income tax purposes, in which case the corresponding tax deduction will have occurred at the time the PG&E Corporation common stock was transferred to the Fire Victim Trust. In January 2021, PG&E Corporation received an IRS ruling that states the Utility is eligible to make a grantor trust election for U.S. federal income tax purposes with respect to the Fire Victim Trust and addressed certain, but not all, related issues. PG&E Corporation believes benefits associated with “grantor trust” treatment could be realized, but only if PG&E Corporation and the Fire Victim Trust can meet certain requirements of the Internal Revenue Code and Treasury Regulations thereunder, relating to sales of PG&E Corporation stock. PG&E Corporation expects to elect grantor trust treatment, subject to entering into a definitive agreement with the Fire Victim Trust. There can be no assurance that such an agreement will be reached or that PG&E Corporation will be able to avail itself of the benefits of a grantor trust election. If PG&E Corporation makes a “grantor trust” election for the Fire Victim Trust, the Utility’s tax deduction will occur only at the time the Fire Victim Trust pays the fire victims and will be impacted by the price at which the Fire Victim Trust sells the shares, rather than the price at the time such shares were contributed to the Fire Victim Trust.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation’s and the Utility’s common stock, beginning the fourth quarter of 2017, as well as the Utility’s preferred stock, beginning the three-month period ending January 31, 2018.

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On April 3, 2019, the court overseeing the Utility’s probation issued an order imposing new conditions of probation, including forgoing issuing “any dividends until [the Utility] is in compliance with all applicable vegetation management requirements” under applicable law and the Utility’s WMP.

On March 20, 2020, PG&E Corporation and the Utility filed a Case Resolution Contingency Process Motion with the Bankruptcy Court that includes a dividend restriction for PG&E Corporation. According to the dividend restriction, PG&E Corporation “will not pay common dividends until it has recognized \$6.2 billion in non-GAAP core earnings following the Effective Date” of the Plan. The Bankruptcy Court entered the order approving the motion on April 9, 2020.

In addition, the Corporation Revolving Credit Agreement requires that PG&E Corporation (1) maintain a ratio of total consolidated debt to consolidated capitalization of no greater than 70% as of the end of each fiscal quarter and (2) if revolving loans are outstanding as of the end of a fiscal quarter, a ratio of adjusted cash to fixed charges, as of the end of such fiscal quarter, of at least 150% prior to the date that PG&E Corporation first declares a cash dividend on its common stock and at least 100% thereafter.

Under the Utility’s Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility’s preferred stock have been paid. Additionally, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average. On May 28, 2020, the CPUC approved a final decision in the Chapter 11 Proceedings OII, which, among other things, grants the Utility a temporary, five-year waiver from compliance with its authorized capital structure for the financing in place upon the Utility’s emergence from Chapter 11.

Subject to the foregoing restrictions, any decision to declare and pay dividends in the future will be made at the discretion of the Boards of Directors and will depend on, among other things, results of operations, financial condition, cash requirements, contractual restrictions and other factors that the Boards of Directors may deem relevant. As of December 31, 2020, it is uncertain when PG&E Corporation and the Utility will commence the payment of dividends on their common stock and when the Utility will commence the payment of dividends on its preferred stock.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including stock options, restricted stock units, performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. As of the Effective Date, the LTIP was amended to increase the maximum number of shares of PG&E Corporation common stock reserved for issuance under the LTIP from 17 million shares to 47 million (subject to certain adjustments), of which 29,174,205 shares were available for future awards at December 31, 2020.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2020:

(in millions)	2020	2019	2018
Stock Options	\$ 3	\$ 7	\$ 10
Restricted stock units	15	21	43
Performance shares	17	22	36

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Total compensation expense (pre-tax)	\$ 35	\$ 50	\$ 89
Total compensation expense (after-tax)	\$ 25	\$ 35	\$ 63

Share-based compensation costs are generally not capitalized. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Stock Options

The exercise price of stock options granted under the LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation's common stock on the date of grant. Stock options generally have a 10-year term and vest over three years of continuous service, subject to accelerated vesting in certain circumstances. As of December 31, 2020, \$0.5 million of total unrecognized compensation costs related to nonvested stock options were expected to be recognized over a weighted average period of 0.16 years for PG&E Corporation.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method in 2019 was \$3.87 per share. No stock options were granted in 2020. The significant assumptions used for shares granted in 2019 were:

	2019
Expected stock price volatility	57.00 %
Expected annual dividend payment	— %
Risk-free interest rate	1.51% to 1.52%
Expected life (years)	4.5

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the date of grant. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant. The expected life of stock options is derived from historical data that estimates stock option exercises and employee departure behavior.

There was no tax benefit recognized from stock options for the year ended December 31, 2020.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2020:

	Number of Stock Options	Weighted Average Grant- Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	4,281,403	\$ 5.98		\$ —
Granted (1)	20,065	3.87		—
Exercised	—	—		—

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Forfeited or expired	(2,080,221)	3.87		—
Outstanding at December 31	2,221,247	7.45	5.33 years	—
Vested or expected to vest at December 31	2,215,076	7.43	5.31 years	—
Exercisable at December 31	1,840,893	\$ 6.86	4.93 years	\$ —

(1) Represents additional payout of existing stock option grants.

Restricted Stock Units

Restricted stock units granted after 2014 generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized ratably over the vesting period based on grant-date fair value. The weighted average grant-date fair value for restricted stock units granted during 2020, 2019, and 2018 was \$9.25, \$18.57, and \$40.92, respectively. The total fair value of restricted stock units that vested during 2020, 2019, and 2018 was \$31 million, \$42 million, and \$41 million, respectively. The tax detriment from restricted stock units that vested in 2020 was \$19 million. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2020, \$6 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.58 years.

The following table summarizes restricted stock unit activity for 2020:

	Number of Restricted Stock Units	Weighted Average Grant- Date Fair Value
Nonvested at January 1	1,040,835	\$ 44.06
Granted	1,007,782	9.25
Vested	(944,090)	33.14
Forfeited	(214,174)	15.75
Nonvested at December 31	890,353	\$ 23.05

Performance Shares

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on either PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period or, for a small number of awards, an internal PG&E Corporation metric. Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

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Compensation expense attributable to performance shares is generally recognized ratably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value of PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2020, 2019, and 2018 was \$9.62, \$15.39, and \$36.92 respectively. The tax detriment from performance shares that vested in 2020 was \$49 million. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2020, \$54 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 2.2 years.

The following table summarizes activity for performance shares in 2020:

	Number of Performance Shares	Weighted Average Grant- Date Fair Value
Nonvested at January 1	688,423	\$ 36.92
Granted	7,951,541	9.62
Vested	(132,526)	41.27
Forfeited ⁽¹⁾	(1,218,656)	24.38
Nonvested at December 31	7,288,782	\$ 9.16

⁽¹⁾ Includes performance shares that expired with zero value as performance targets were not met.

NOTE 7: PREFERRED STOCK

PG&E Corporation has authorized 400 million shares of preferred stock, none of which is outstanding.

The Utility has authorized 75 million shares of first preferred stock, with a par value of \$25 per share, and 10 million shares of \$100 first preferred stock, with a par value of \$100 per share. At December 31, 2020 and December 31, 2019, the Utility's preferred stock outstanding included \$145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and \$113 million of shares with interest rates between 4.36% and 5% that are redeemable between \$25.75 and \$27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. No shares of \$100 first preferred stock are outstanding.

At December 31, 2020, annual dividends on the Utility's nonredeemable preferred stock ranged from \$1.25 to \$1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2020, annual dividends on redeemable preferred stock ranged from \$1.09 to \$1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The Utility paid no dividends on preferred stock in 2020, 2019, or 2018.

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NOTE 8: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income (loss) available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income (loss) available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2020, 2019, and 2018.

(in millions, except per share amounts)	Year Ended December 31,		
	2020	2019	2018
Loss attributable to common shareholders	\$ (1,318)	\$ (7,656)	\$ (6,851)
Weighted average common shares outstanding, basic	1,257	528	517
Add incremental shares from assumed conversions:			
Employee share-based compensation	—	—	—
Equity Units	—	—	—
Weighted average common share outstanding, diluted	1,257	528	517
Total Loss per common share, diluted	\$ (1.05)	\$ (14.50)	\$ (13.25)

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 9: INCOME TAXES

PG&E Corporation and the Utility use the asset and liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, the difference between a tax position taken or expected to be taken in a tax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation amortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

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PG&E Corporation files a consolidated U.S. federal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agreement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows:

(in millions)	PG&E Corporation			Utility		
	Year Ended December 31,					
	2020	2019	2018	2020	2019	2018
Current:						
Federal	\$ (26)	\$ 1	\$ (5)	\$ (26)	\$ 4	\$ 5
State	(34)	101	(8)	(34)	94	(7)
Deferred:						
Federal	258	(2,361)	(2,264)	290	(2,363)	(2,278)
State	171	(1,136)	(1,009)	185	(1,137)	(1,009)
Tax credits	(7)	(5)	(6)	(7)	(5)	(6)
Income tax provision (benefit)	\$ 362	\$ (3,400)	\$ (3,292)	\$ 408	\$ (3,407)	\$ (3,295)

The following tables describe net deferred income tax assets and liabilities:

(in millions)	PG&E Corporation		Utility	
	Year Ended December 31,			
	2020	2019	2020	2019
Deferred income tax assets:				
Tax carryforwards	\$ 7,641	\$ 1,390	\$ 7,529	\$ 1,308
Compensation	187	151	109	92
Wildfire-related claims ⁽¹⁾	544	6,520	544	6,520
Operating lease liability	489	642	488	640
Other ⁽²⁾	212	112	219	121
Total deferred income tax assets	\$ 9,073	\$ 8,815	\$ 8,889	\$ 8,681
Deferred income tax liabilities:				
Property related basis differences	8,311	7,984	8,300	7,973
Regulatory balancing accounts	763	381	763	381
Debt financing costs	526	—	526	—

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Operating lease right of use asset	489	642	488	640
Income tax regulatory asset ⁽³⁾	254	71	254	71
Other ⁽⁴⁾	128	57	128	58
Total deferred income tax liabilities	\$ 10,471	\$ 9,135	\$ 10,459	\$ 9,123
Total net deferred income tax liabilities	\$ 1,398	\$ 320	\$ 1,570	\$ 442

(1) Amounts primarily relate to wildfire-related claims, net of estimated insurance recoveries, and legal and other costs related to various wildfires that have occurred on PG&E Corporation's and the Utility's service territory over the past several years.

(2) Amounts include benefits, environmental reserve, and customer advances for construction.

(3) Represents the tax gross up portion of the deferred income tax for the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized for tax, including the impact of changes in net deferred taxes associated with a lower federal income tax rate as a result of the Tax Act.

(4) Amount primarily includes an environmental reserve.

The following table reconciles income tax expense at the federal statutory rate to the income tax provision:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2020	2019	2018	2020	2019	2018
Federal statutory income tax rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) ⁽¹⁾	(15.3)	7.5	7.9	19.1	7.5	7.9
Effect of regulatory treatment of fixed asset differences ⁽²⁾	39.0	2.8	3.6	(44.9)	2.8	3.6
Tax credits	1.5	0.1	0.1	(1.7)	0.1	0.1
Bankruptcy and emergence ⁽³⁾	(82.5)	—	—	54.1	—	—
Other, net ⁽⁴⁾	(2.1)	(0.6)	(0.1)	2.2	(0.5)	—
Effective tax rate	(38.4)%	30.8 %	32.5 %	49.8 %	30.9 %	32.6 %

(1) Includes the effect of state flow-through ratemaking treatment.

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. In 2020, 2019, and 2018, the amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December 2017.

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- (3) The Utility includes an adjustment for the measurement of the deferred tax asset associated with the difference between the liability recorded related to the TCC RSA and the ultimate value of PG&E Corporation stock contributed to the Fire Victim Trust. PG&E Corporation includes the same adjustment as the Utility and a permanent non-deductible equity backstop premium expense. This combined with a pre-tax loss and a pre-tax income for PG&E Corporation and the Utility, respectively, accounts for the remaining difference.
- (4) These amounts primarily represent the impact of tax audit settlements and non-tax deductible costs in 2020 and 2019.

Unrecognized Tax Benefits

The following table reconciles the changes in unrecognized tax benefits:

(in millions)	PG&E Corporation			Utility		
	2020	2019	2018	2020	2019	2018
Balance at beginning of year	\$ 420	\$ 377	\$ 349	\$ 420	\$ 377	\$ 349
Reductions for tax position taken during a prior year	(43)	(1)	(27)	(43)	(1)	(27)
Additions for tax position taken during the current year	60	44	55	60	44	55
Settlements	—	—	—	—	—	—
Expiration of statute	—	—	—	—	—	—
Balance at end of year	\$ 437	\$ 420	\$ 377	\$ 437	\$ 420	\$ 377

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2020 for PG&E Corporation and the Utility was \$16 million.

PG&E Corporation's and the Utility's unrecognized tax benefits are not likely to change significantly within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of Income. For the years ended December 31, 2020, 2019, and 2018, these amounts were immaterial.

Tax Settlements

PG&E Corporation's tax returns have been accepted through 2015 for federal income tax purposes, except for a few matters, the most significant of which relate to deductible repair costs for gas transmission and distribution lines of business and tax deductions claimed for regulatory fines and fees assessed as part of the penalty decision issued in 2015 for the San Bruno natural gas explosion in September of 2010.

Tax years after 2007 remain subject to examination by the State of California.

Carryforwards

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances:

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(in millions)	December 31, 2020	Expiration Year
Federal:		
Net operating loss carryforward - Pre-2018	\$ 3,600	2031 - 2036
Net operating loss carryforward - Post-2017	24,887	N/A
Tax credit carryforward	134	2029 - 2040
State:		
Net operating loss carryforward	\$ 25,364	2039 - 2040
Tax credit carryforward	100	Various

On the Petition Date, PG&E Corporation and the Utility filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. PG&E Corporation does not believe that the Chapter 11 Cases resulted in loss of or limitation on the utilization of any of the tax carryforwards. PG&E Corporation will continue to monitor the status of tax carryforwards.

Other Tax Matters

PG&E Corporation's and the Utility's unrecognized tax benefits are not likely to change significantly within the next 12 months. At December 31, 2020, it is reasonably possible that within the next 12 months, unrecognized tax benefits will decrease. The amount is not expected to be material.

As of the date of this report, PG&E Corporation does not believe that it had undergone an ownership change, and consequently, its net operating loss carryforwards and other tax attributes are not limited by Section 382 of the Internal Revenue Code.

In March 2020, Congress passed, and the President signed into law the Coronavirus Aid, Relief and Economic Security ("CARES") Act. Under the CARES Act, PG&E Corporation and the Utility have deferred the payment of 2020 payroll taxes for the remainder of the year to 2021 and 2022.

During June 2020, the State of California enacted AB 85, which increases taxes on corporations over a three-year period beginning in 2020 by suspension of the net operating loss deduction and a limit of \$5 million per year on business tax credits. PG&E Corporation and the Utility do not anticipate any material impacts to PG&E Corporation's Consolidated Financial Statements due to this legislation.

In December 2020, Congress passed, and the President signed into law the Consolidations and Appropriations Act of 2021. PG&E Corporation and the Utility do not expect this legislation to have a material impact to PG&E Corporation's Consolidated Financial Statements.

See "Ownership Restrictions in PG&E Corporation's Amended Articles" in Note 6 of the Notes to the Consolidated Financial Statements in Item 8 for information on the possible election to treat the Fire Victim Trust as a "grantor trust" for federal income tax purposes.

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NOTE 10: DERIVATIVES

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Derivatives are presented in the Utility's Consolidated Balance Sheets and recorded at fair value and on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the Consolidated Balance Sheets at fair value.

Volume of Derivative Activity

The volumes of the Utility's outstanding derivatives were as follows:

Underlying Product	Instruments	Contract Volume	
		2020	2019
Natural Gas ⁽¹⁾ (MMBtus) ⁽²⁾	Forwards, Futures and Swaps	146,642,863	131,896,159
	Options	14,140,000	14,720,000
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	9,435,830	18,675,852
	Options	—	—
	Congestion Revenue Rights ⁽³⁾	266,091,470	308,467,999

⁽¹⁾ Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

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(2) Million British Thermal Units.

(3) CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At December 31, 2020, the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk			Total Derivative Balance
	Gross Derivative Balance	Netting	Cash Collateral	
Current assets – other	\$ 33	\$ —	\$ 115	\$ 148
Other noncurrent assets – other	136	—	—	136
Current liabilities – other	(38)	—	15	(23)
Noncurrent liabilities – other	(204)	—	10	(194)
Total commodity risk	\$ (73)	\$ —	\$ 140	\$ 67

At December 31, 2019, the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk			Total Derivative Balance
	Gross Derivative Balance	Netting	Cash Collateral	
Current assets – other	\$ 36	\$ (6)	\$ 4	\$ 34
Other noncurrent assets – other	130	(6)	—	124
Current liabilities – other	(31)	6	2	(23)
Noncurrent liabilities – other	(130)	6	—	(124)
Total commodity risk	\$ 5	\$ —	\$ 6	\$ 11

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Consolidated Statements of Cash Flows.

Some of the Utility's derivatives instruments, including power purchase agreements, contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies, also known as a credit-risk-related contingent feature. Multiple credit agencies continue to rate the Utility below investment grade, which results in the Utility posting additional collateral. As of December 31, 2020, the Utility satisfied or has otherwise addressed its obligations related to the credit-risk related contingency features.

NOTE 11: FAIR VALUE MEASUREMENTS

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PG&E Corporation and the Utility measure their cash equivalents, trust assets and price risk management instruments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1** – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2** – Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3** – Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

(in millions)	Fair Value Measurements				
	At December 31, 2020				
	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	\$ 470	\$ —	\$ —	\$ —	\$ 470
Nuclear decommissioning trusts					
Short-term investments	27	—	—	—	27
Global equity securities	2,398	—	—	—	2,398
Fixed-income securities	924	835	—	—	1,759
Assets measured at NAV	—	—	—	—	25
Total nuclear decommissioning trusts (2)	3,349	835	—	—	4,209
Price risk management instruments (Note 10)					
Electricity	—	2	166	2	170
Gas	—	1	—	113	114
Total price risk management instruments	—	3	166	115	284
Rabbi trusts					
Fixed-income securities	—	106	—	—	106
Life insurance contracts	—	79	—	—	79
Total rabbi trusts	—	185	—	—	185
Long-term disability trust					
Short-term investments	9	—	—	—	9

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Assets measured at NAV	—	—	—	—	158
Total long-term disability trust	9	—	—	—	167
TOTAL ASSETS	\$ 3,828	\$ 1,023	\$ 166	\$ 115	\$ 5,315
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	\$ —	\$ 1	\$ 238	\$ (25)	\$ 214
Gas	—	3	—	—	3
TOTAL LIABILITIES	\$ —	\$ 4	\$ 238	\$ (25)	\$ 217

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and cash collateral.

(2) Represents amount before deducting \$671 million, primarily related to deferred taxes on appreciation of investment value.

Fair Value Measurements

At December 31, 2019

(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	\$ 1,323	\$ —	\$ —	\$ —	\$ 1,323
Nuclear decommissioning trusts					
Short-term investments	6	—	—	—	6
Global equity securities	2,086	—	—	—	2,086
Fixed-income securities	862	728	—	—	1,590
Assets measured at NAV	—	—	—	—	21
Total nuclear decommissioning trusts (2)	2,954	728	—	—	3,703
Price risk management instruments (Note 10)					
Electricity	—	2	161	(11)	152
Gas	—	3	—	3	6
Total price risk management instruments	—	5	161	(8)	158
Rabbi trusts					
Fixed-income securities	—	100	—	—	100
Life insurance contracts	—	73	—	—	73

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Total rabbi trusts	—	173	—	—	173
Long-term disability trust					
Short-term investments	10	—	—	—	10
Assets measured at NAV	—	—	—	—	156
Total long-term disability trust	10	—	—	—	166
TOTAL ASSETS	\$ 4,287	\$ 906	\$ 161	\$ (8)	\$ 5,523
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	1	2	156	(13)	146
Gas	—	2	—	(1)	1
TOTAL LIABILITIES	\$ 1	\$ 4	\$ 156	\$ (14)	\$ 147

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and cash collateral.

(2) Represents amount before deducting \$530 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed. There were no material transfers between any levels for the years ended December 31, 2020 and 2019.

Trust Assets

Assets Measured at Fair Value

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

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Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of fixed-income securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. The Utility utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

Level 3 Measurements and Uncertainty Analysis

Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. See Note 10 above.

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(in millions)	Fair Value at		Valuation Technique	Unobservable Input	Range (1)/Weighted-Average Price (2)
	At December 31, 2020				
Fair Value Measurement	Assets	Liabilities			
Congestion revenue rights	\$ 153	\$ 74	Market approach	CRR auction prices	\$ (320.25) - 320.25 / 0.30
Power purchase agreements	\$ 13	\$ 164	Discounted cash flow	Forward prices	\$ 12.56 - 148.30 / 35.52

(1) Represents price per megawatt-hour.

(2) Unobservable inputs were weighted by the relative fair value of the instruments.

(in millions)	Fair Value at		Valuation Technique	Unobservable Input	Range (1)/Weighted-Average Price (2)
	At December 31, 2019				
Fair Value Measurement	Assets	Liabilities			
Congestion revenue rights	\$ 140	\$ 44	Market approach	CRR auction prices	\$ (20.20) - 20.20 / 0.28
Power purchase agreements	\$ 21	\$ 112	Discounted cash flow	Forward prices	\$ 11.77 - 59.38 / 33.62

(1) Represents price per megawatt-hour.

(2) Unobservable inputs were weighted by the relative fair value of the instruments.

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2020 and 2019, respectively:

(in millions)	Price Risk Management Instruments	
	2020	2019
Asset (liability) balance as of January 1	\$ 5	\$ 95
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(77)	(90)
Asset (liability) balance as of December 31	\$ (72)	\$ 5

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(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2020 and 2019, as they are short-term in nature.

The carrying amount and fair value of PG&E Corporation's and the Utility's long-term debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

(in millions)	At December 31,			
	2020		2019	
	Carrying Amount	Level 2 Fair Value	Carrying Amount ⁽¹⁾	Level 2 Fair Value ⁽¹⁾⁽²⁾
Debt (Note 5)				
PG&E Corporation	\$ 1,901	\$ 2,175	\$ —	\$ —
Utility	29,664	32,632	1,500	1,500

(1) On January 29, 2019 PG&E Corporation and the Utility filed for Chapter 11 protection. Debt held by PG&E Corporation became debt subject to compromise and is valued at the allowed claim amount. For more information, see Note 2 and Note 5.

(2) The fair value of the Utility pre-petition debt was \$17.9 billion as of December 31, 2019. For more information, see Note 2 and Note 5.

Nuclear Decommissioning Trust Investments

The following table provides a summary of equity securities and available-for-sale debt securities:

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of December 31, 2020				
Nuclear decommissioning trusts				
Short-term investments	\$ 27	\$ —	\$ —	\$ 27
Global equity securities	543	1,881	(1)	2,423
Fixed-income securities	1,610	152	(3)	1,759
Total (1)	\$ 2,180	\$ 2,033	\$ (4)	\$ 4,209
As of December 31, 2019				

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Nuclear decommissioning trusts

Short-term investments	\$ 6	\$ —	\$ —	\$ 6
Global equity securities	500	1,609	(2)	2,107
Fixed-income securities	1,505	89	(4)	1,590
Total (1)	\$ 2,011	\$ 1,698	\$ (6)	\$ 3,703

(1) Represents amounts before deducting \$671 million and \$530 million at December 31, 2020 and 2019, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

(in millions)	As of December 31, 2020
Less than 1 year	\$ 50
1–5 years	475
5–10 years	403
More than 10 years	831
Total maturities of fixed-income securities	\$ 1,759

The following table provides a summary of activity for the fixed-income and equity securities:

(in millions)	2020	2019	2018
Proceeds from sales and maturities of nuclear decommissioning investments	\$ 1,518	\$ 956	\$ 1,412
Gross realized gains on securities	159	69	54
Gross realized losses on securities	(41)	(14)	(24)

NOTE 12: EMPLOYEE BENEFIT PLANS

Pension Plan and Postretirement Benefits Other than Pensions (“PBOP”)

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate (“Pension Plan”). Certain trusts underlying these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation’s and the Utility’s funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. On an annual basis, the Utility funds the pension plans up to the amount it is authorized to recover in rates.

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PG&E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utility use a fiscal year-end measurement date for all plans.

Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2020 and 2019:

Pension Plan

(in millions)	2020	2019
Change in plan assets:		
Fair value of plan assets at beginning of year	\$ 18,547	\$ 15,312
Actual return on plan assets	2,736	3,713
Company contributions	343	328
Benefits and expenses paid	(867)	(806)
Fair value of plan assets at end of year	\$ 20,759	\$ 18,547
Change in benefit obligation:		
Benefit obligation at beginning of year	\$ 20,525	\$ 17,407
Service cost for benefits earned	530	443
Interest cost	713	758
Actuarial loss ⁽¹⁾	2,271	2,723
Plan amendments	—	—
Benefits and expenses paid	(867)	(806)
Benefit obligation at end of year ⁽²⁾	\$ 23,172	\$ 20,525
Funded Status:		
Current liability	\$ (3)	\$ (14)
Noncurrent liability	(2,410)	(1,964)
Net liability at end of year	\$ (2,413)	\$ (1,978)

⁽¹⁾ The actuarial losses for the years ended December 31, 2020 and 2019 were primarily due to a decrease in the discount rate used to measure the projected benefit obligation. The actuarial loss for the year ended December 31, 2019 was also driven by unfavorable changes in the demographic assumptions used to measure the projected benefit obligation.

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(2) PG&E Corporation's accumulated benefit obligation was \$20.7 billion and \$18.4 billion at December 31, 2020 and 2019, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2020	2019
Change in plan assets:		
Fair value of plan assets at beginning of year	\$ 2,678	\$ 2,258
Actual return on plan assets	379	474
Company contributions	26	29
Plan participant contribution	81	82
Benefits and expenses paid	(169)	(165)
Fair value of plan assets at end of year	\$ 2,995	\$ 2,678
Change in benefit obligation:		
Benefit obligation at beginning of year	\$ 1,832	\$ 1,745
Service cost for benefits earned	61	56
Interest cost	63	76
Actuarial (gain) loss ⁽¹⁾	(14)	22
Benefits and expenses paid	(149)	(150)
Federal subsidy on benefits paid	3	2
Plan participant contributions	80	81
Benefit obligation at end of year	\$ 1,876	\$ 1,832
Funded Status: (2)		
Noncurrent asset	\$ 1,153	\$ 879
Noncurrent liability	(34)	(33)
Net asset at end of year	\$ 1,119	\$ 846

(1) The actuarial gain for the year ended December 31, 2020 was primarily due to favorable changes in the demographic and medical cost assumptions, offset by a decrease in the discount rate used to measure the projected benefit obligation. The actuarial loss for the year ended December 31, 2019 was primarily due to a decrease in the discount rate used to measure the projected benefit obligation, offset by favorable changes in the demographic assumptions and the elimination of excise tax.

(2) At December 31, 2020 and 2019, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position. The projected benefit obligation and the fair value of plan assets for the postretirement life insurance plan were \$377 million and \$343 million as of December 31, 2020, and \$337 million and \$305 million as of December 31, 2019, respectively.

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There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Components of Net Periodic Benefit Cost

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

Pension Plan

(in millions)	2020	2019	2018
Service cost for benefits earned (1)	\$ 530	\$ 443	\$ 514
Interest cost	713	758	687
Expected return on plan assets	(1,044)	(906)	(1,021)
Amortization of prior service cost	(6)	(6)	(6)
Amortization of net actuarial loss	3	3	5
Net periodic benefit cost	196	292	179
Less: transfer to regulatory account (2)	136	42	157
Total expense recognized	\$ 332	\$ 334	\$ 336

(1) A portion of service costs are capitalized pursuant to ASU 2017-07.

(2) The Utility recorded these amounts to a regulatory account as they are probable of recovery from customers in future rates.

Postretirement Benefits Other than Pensions

(in millions)	2020	2019	2018
Service cost for benefits earned (1)	\$ 61	\$ 56	\$ 66
Interest cost	63	76	69
Expected return on plan assets	(138)	(123)	(130)
Amortization of prior service cost	14	14	14
Amortization of net actuarial loss	(21)	(3)	(5)
Net periodic benefit cost	\$ (21)	\$ 20	\$ 14

(1) A portion of service costs are capitalized pursuant to ASU 2017-07.

Non-service costs are reflected in Other income, net on the Consolidated Statements of Income. Service costs are reflected in Operating and maintenance on the Consolidated Statements of Income.

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There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Components of Accumulated Other Comprehensive Income

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax. In addition, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension benefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts that would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

Valuation Assumptions

The following weighted average year-end actuarial assumptions were used in determining the plans' projected benefit obligations and net benefit costs.

	Pension Plan			PBOP Plans		
	December 31,			December 31,		
	2020	2019	2018	2020	2019	2018
Discount rate	2.77 %	3.46 %	4.35 %	2.67 - 2.80%	3.37 - 3.47%	4.29 - 4.37%
Rate of future compensation increases	3.80 %	3.90 %	3.90 %	N/A	N/A	N/A
Expected return on plan assets	5.10 %	5.70 %	6.00 %	3.10 - 6.10%	3.50 - 6.60%	3.60 - 6.80%
Interest crediting rate for cash balance plan	1.95 %	2.11 %	3.15 %	N/A	N/A	N/A

The assumed health care cost trend rate as of December 31, 2020 was 6.3%, gradually decreasing to the ultimate trend rate of approximately 4.5% in 2028 and beyond.

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Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were projected based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 5.1% compares to a ten-year actual return of 9.6%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 835 Aa-grade non-callable bonds at December 31, 2020. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs in financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings. Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility, PG&E Corporation's and the Utility's trusts hold significant allocations in long maturity fixed-income investments. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, global real estate investment trusts ("REITS"), global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

	Pension Plan			PBOP Plans		
	2021	2020	2019	2021	2020	2019
Global equity securities	30 %	30 %	29 %	36 %	28 %	33 %
Absolute return	2 %	2 %	5 %	1 %	2 %	3 %
Real assets	8 %	8 %	8 %	5 %	8 %	6 %
Fixed-income securities	60 %	60 %	58 %	58 %	62 %	58 %
Total	100 %	100 %	100 %	100 %	100 %	100 %

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PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles and responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriate use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2020 and 2019.

(in millions)	Fair Value Measurements							
	At December 31,							
	2020				2019			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Plan:								
Short-term investments	\$ 334	\$ 408	\$ —	\$ 742	\$ 613	\$ 231	\$ —	\$ 844
Global equity securities	1,875	—	—	1,875	1,650	—	—	1,650
Absolute Return	1	1	—	2	—	1	—	1
Real assets	517	—	—	517	548	1	—	549
Fixed-income securities	2,467	7,154	12	9,633	2,227	6,413	15	8,655
Assets measured at NAV	—	—	—	8,224	—	—	—	6,937
Total	\$ 5,194	\$ 7,563	\$ 12	\$ 20,993	\$ 5,038	\$ 6,646	\$ 15	\$ 18,636
PBOP Plans:								
Short-term investments	\$ 37	\$ —	\$ —	\$ 37	\$ 37	\$ —	\$ —	\$ 37
Global equity securities	173	—	—	173	151	—	—	151
Real assets	54	—	—	54	58	—	—	58
Fixed-income securities	481	715	1	1,197	193	875	1	1,069
Assets measured at NAV	—	—	—	1,549	—	—	—	1,373
Total	\$ 745	\$ 715	\$ 1	\$ 3,010	\$ 439	\$ 875	\$ 1	\$ 2,688
Total plan assets at fair value				\$ 24,003				\$ 21,324

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net liabilities of \$249 million and other net liabilities of \$99 million at December 31, 2020 and 2019, respectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

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Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the table above. All investments that are valued using a net asset value per share can be redeemed quarterly with a notice not to exceed 90 days.

Short-Term Investments

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

Global Equity securities

The global equity category includes investments in common stock and equity-index futures. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets.

Real Assets

The real asset category includes portfolios of commodity futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets.

Fixed-Income securities

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

Investments in the trusts that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities, asset-backed securities, and private real estate funds. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Transfers Between Levels

No material transfers between levels occurred in the years ended December 31, 2020 and 2019.

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Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for the pension plan that have been classified as Level 3 for the years ended December 31, 2020 and 2019:

(in millions)

For the year ended December 31, 2020	<u>Fixed-Income</u>
Balance at beginning of year	\$ 15
Actual return on plan assets:	
Relating to assets still held at the reporting date	2
Relating to assets sold during the period	(3)
Purchases, issuances, sales, and settlements:	
Purchases	11
Settlements	(13)
Balance at end of year	\$ 12

(in millions)

For the year ended December 31, 2019	<u>Fixed-Income</u>
Balance at beginning of year	\$ 8
Actual return on plan assets:	
Relating to assets still held at the reporting date	—
Relating to assets sold during the period	—
Purchases, issuances, sales, and settlements:	
Purchases	11
Settlements	(4)
Balance at end of year	\$ 15

There were no material transfers out of Level 3 in 2020 and 2019.

Cash Flow Information

Employer Contributions

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PG&E Corporation and the Utility contributed \$343 million to the pension benefit plans and \$26 million to the other benefit plans in 2020. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2020. The Utility's pension benefits met all the funding requirements under Employee Retirement Income Security Act. PG&E Corporation and the Utility expect to make total contributions of approximately \$327 million and \$15 million to the pension plan and other postretirement benefit plans, respectively, for 2021.

Benefits Payments and Receipts

As of December 31, 2020, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	Pension Plan	PBOP Plans	Federal Subsidy
2021	831	85	(6)
2022	913	89	(6)
2023	948	92	(6)
2024	980	93	(7)
2025	1,009	95	(7)
Thereafter in the succeeding five years	5,375	471	(41)

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

Retirement Savings Plan

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were \$119 million, \$109 million, and \$105 million in 2020, 2019, and 2018, respectively. Beginning January 1, 2019 PG&E Corporation changed its default matching contributions under its 401(k) plan from PG&E Corporation common stock to cash. Beginning in March 2019, at PG&E Corporation's directive, the 401(k) plan trustee began purchasing new shares in the PG&E Corporation common stock fund on the open market rather than directly from PG&E Corporation.

There were no material differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

NOTE 13: RELATED PARTY AGREEMENTS AND TRANSACTIONS

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The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are generally priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were:

(in millions)	Year Ended December 31,		
	2020	2019	2018
Utility revenues from:			
Administrative services provided to PG&E Corporation	\$ 3	\$ 4	\$ 4
Utility expenses from:			
Administrative services received from PG&E Corporation	\$ 108	\$ 107	\$ 94
Utility employee benefit due to PG&E Corporation	34	42	76

At December 31, 2020 and 2019, the Utility had receivables of \$35 million and \$60 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of \$46 million and \$118 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 14: WILDFIRE-RELATED CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to wildfires. A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can be reasonably estimated. PG&E Corporation and the Utility evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of losses is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly, and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

2015 Butte Fire

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In September 2015, a wildfire (the “2015 Butte fire”) ignited and spread in Amador and Calaveras Counties in Northern California. Cal Fire concluded that the 2015 Butte fire was caused when a gray pine tree contacted the Utility’s electric line, which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

During the quarter ended September 30, 2020, the remaining 2015 Butte fire claims were satisfied and discharged in accordance with the Plan. See “Pre-Petition Wildfire-Related Claims and Discharge Upon Plan Effective Date” and “District Attorneys’ Office Investigations” below for more information on the 2015 Butte fire.

2018 Camp Fire and 2017 Northern California Wildfires Background

According to Cal Fire, on November 8, 2018 at approximately 6:33 a.m., a wildfire began near the city of Paradise, Butte County, California (the “2018 Camp fire”), which is located in the Utility’s service territory. Cal Fire’s Camp Fire Incident Information Website as of November 15, 2019 (the “Cal Fire website”) indicated that the 2018 Camp fire consumed 153,336 acres. On the Cal Fire website, Cal Fire reported 85 fatalities and the destruction of 18,804 structures resulting from the 2018 Camp fire.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the “2017 Northern California wildfires”). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the 2017 Northern California wildfires, there were 21 major fires that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The 2017 Northern California wildfires resulted in 44 fatalities.

PG&E Corporation and the Utility were subject to numerous claims in connection with the 2018 Camp fire and 2017 Northern California wildfires. These included claims by various groups of wildfire victims, including individual plaintiffs, holders of insurance subrogation claims, and various federal, state and local entities. During the quarter ended September 30, 2020, these claims were satisfied and discharged in accordance with the Plan, as described below.

Pre-petition Wildfire-Related Claims and Discharge Upon Plan Effective Date

Pre-petition wildfire-related claims on the Consolidated Financial Statements include amounts associated with the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire.

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On July 1, 2020, pursuant to the Plan, PG&E Corporation and the Utility funded the Fire Victim Trust with \$5.4 billion in cash (with an additional \$1.35 billion to be funded on a deferred basis), 477 million shares of common stock of PG&E Corporation (representing 22.19% of the outstanding common stock of PG&E Corporation as of the Effective Date (subject to potential adjustments)), plus the assignment of certain rights and causes of action. Additionally, as a result of the Additional Units Issuance, on August 3, 2020, PG&E Corporation made an equity contribution of 748,415 shares to the Utility which delivered such additional shares of common stock to the Fire Victim Trust pursuant to an anti-dilution provision in the Fire Victim Trust Assignment Agreement. In accordance with the Plan and the Confirmation Order, as a result of such funding, all Fire Victim Claims have been fully and finally satisfied, released and discharged and channeled to the Fire Victim Trust with no recourse to PG&E Corporation or the Utility. Accordingly, \$12.15 billion of the \$13.5 billion liability as of June 30, 2020 was extinguished in the third quarter of 2020, and the remaining \$1.35 billion will be paid out under the terms of the Tax Benefits Payment Agreement, as described in Note 2 under the heading “Significant Bankruptcy Court Actions.” On January 15, 2021, the Utility paid approximately \$758 million of the \$1.35 billion, pursuant to the Tax Benefits Payment Agreement.

On July 1, 2020, PG&E Corporation and the Utility funded the Subrogation Wildfire Trust for the benefit of holders of Subrogation Claims in the amount of \$11.0 billion in cash and paid approximately \$43 million in respect of professional fees of such claimants, for a total of approximately \$52 million for subrogation wildfire claimants’ professional fees. Such amount was initially funded into escrow and later paid to the Subrogation Wildfire Trust. In accordance with the Plan and the Confirmation Order, as a result of such funding, all Subrogation Claims have been satisfied, released and discharged and channeled to the Subrogation Wildfire Trust with no recourse to PG&E Corporation or the Utility. Accordingly, the \$11.0 billion liability accrual for Subrogation Claims and \$47.5 million liability for professional fees were extinguished in the third quarter of 2020.

On July 1, 2020, PG&E Corporation and the Utility paid \$1.0 billion in cash to the Settling Public Entities and established a segregated fund in the amount of \$10 million to be used to reimburse the Settling Public Entities for any and all legal fees and costs associated with the defense or resolution of any third party claims against the Settling Public Entities. In accordance with the Plan and the Confirmation Order, as a result of such payments, the \$1.0 billion liability for the Public Entity Wildfire Claims (as defined below) was satisfied, released and discharged in the third quarter of 2020.

Plan Support Agreements with Public Entities

On June 18, 2019, PG&E Corporation and the Utility entered into PSAs with certain local public entities (collectively, the “Supporting Public Entities”) providing for an aggregate of \$1.0 billion to be paid by PG&E Corporation and the Utility to such public entities pursuant to the Plan in order to fully and finally settle and discharge such public entities’ claims against PG&E Corporation and the Utility relating to the 2018 Camp fire, 2017 Northern California wildfires and 2015 Butte fire (collectively, “Public Entity Wildfire Claims”).

The PSAs also provide that, following the Effective Date, PG&E Corporation and the Utility would create and promptly fund \$10 million to a segregated fund to be used by the Supporting Public Entities collectively in connection with the defense or resolution of claims against the Supporting Public Entities by third parties relating to the wildfires noted above (“Third Party Claims”).

These elements were incorporated into the Plan which was approved by the Bankruptcy Court in the Confirmation Order. As described in Note 2 under the heading “Significant Bankruptcy Court Actions,” the actions required by each PSA were taken on or around the Effective Date.

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Restructuring Support Agreement with Holders of Subrogation Claims

On September 22, 2019, PG&E Corporation and the Utility entered into the Subrogation RSA. The Subrogation RSA provides for an aggregate amount of \$11.0 billion to be paid by PG&E Corporation and the Utility pursuant to the Plan in order to fully and finally settle the Subrogation Claims, upon the terms and conditions set forth in the Subrogation RSA. Under the Subrogation RSA, PG&E Corporation and the Utility also agreed to reimburse the holders of Subrogation Claims for professional fees of up to \$55 million, upon the terms and conditions set forth in the Subrogation RSA.

As described above under the heading “Pre-petition Wildfire-Related Claims and Discharge Upon Plan Effective Date,” the payments described in the Subrogation RSA were made on the Effective Date.

Restructuring Support Agreement with the TCC

On December 6, 2019, PG&E Corporation and the Utility entered into the TCC RSA. The TCC RSA (as incorporated into the Plan) provides for, among other things, a combination of cash and common stock of the reorganized PG&E Corporation to be provided by PG&E Corporation and the Utility pursuant to the Plan (together with certain additional rights, the “Aggregate Fire Victim Consideration”) in order to settle and discharge the Fire Victim Claims, upon the terms and conditions set forth in the TCC RSA and the Plan. The Aggregate Fire Victim Consideration that has funded and will fund the Fire Victim Trust pursuant to the Plan for the benefit of holders of the Fire Victim Claims consists of (a) \$5.4 billion in cash that was contributed on the Effective Date of the Plan, (b) \$1.35 billion in cash consisting of (i) \$758 million that was paid in cash on January 15, 2021 and (ii) the remaining balance of \$592 million to be paid in cash on or before January 15, 2022, in each case pursuant to the terms of the Tax Benefits Payment Agreement, and (c) an amount of common stock of the reorganized PG&E Corporation valued at 14.9 times Normalized Estimated Net Income (as defined in the TCC RSA), except that the Fire Victim Trust’s share ownership of the reorganized PG&E Corporation would not be less than 20.9% based on the number of fully diluted shares of the reorganized PG&E Corporation outstanding as of the Effective Date of the Plan, assuming the Utility’s allowed ROE as of the date of the TCC RSA. Under certain circumstances, including certain change of control transactions and in connection with the monetization of certain tax benefits related to the payment of wildfire-related claims, the payments described in clause (b) will be accelerated and payable upon an earlier date. The Aggregate Fire Victim Consideration also included (1) the assignment by PG&E Corporation and the Utility to the Fire Victim Trust of certain rights and causes of action related to the 2015 Butte fire, the 2017 Northern California wildfires and the 2018 Camp fire (together, the “Fires”) that PG&E Corporation and the Utility may have against certain third parties and (2) the assignment of rights under the 2015 insurance policies to resolve any claims related to the Fires in those policy years, other than the rights of PG&E Corporation and the Utility to be reimbursed under the 2015 insurance policies for claims submitted to and paid by PG&E Corporation and the Utility prior to the Petition Date to resolve any claims related to the Fires in those policy years. Pursuant to a stipulation approved by the Bankruptcy Court on June 12, 2020, PG&E Corporation and the Utility and the TCC, and the trustee of the Fire Victim Trust agreed that the percentage ownership of the Fire Victim Trust would be 22.19% of the outstanding shares of the PG&E Corporation on the Effective Date, subject to potential adjustments.

As described above under the heading “Pre-petition Wildfire-Related Claims and Discharge Upon Plan Effective Date,” the funding to be made pursuant to the TCC RSA and the Plan was made on the Effective Date.

2019 Kincade Fire

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According to Cal Fire, on October 23, 2019 at approximately 9:27 p.m., a wildfire began northeast of Geyserville in Sonoma County, California (the “2019 Kincade fire”), located in the service territory of the Utility. The Cal Fire Kincade Fire Incident Update dated November 20, 2019, 11:02 a.m. Pacific Time (the “incident update”) indicated that the 2019 Kincade fire had consumed 77,758 acres. In the incident update, Cal Fire reported no fatalities and four first responder injuries. The incident update also indicates the following: structures destroyed, 374 (consisting of 174 residential structures, 11 commercial structures and 189 other structures); and structures damaged, 60 (consisting of 35 residential structures, one commercial structure and 24 other structures). In connection with the 2019 Kincade fire, state and local officials issued numerous mandatory evacuation orders and evacuation warnings at various times for certain areas of the region. Based on County of Sonoma information, PG&E Corporation and the Utility understand that the geographic zones subject to either a mandatory evacuation order or an evacuation warning between October 23, 2019 and November 4, 2019 included approximately 200,000 persons.

On October 23, 2019, by 3:00 p.m. Pacific Time, the Utility had conducted a PSPS event and turned off the power to approximately 27,837 customers in Sonoma County, including Geyserville and the surrounding area. As part of the PSPS, the Utility’s distribution lines in these areas were deenergized. Following the Utility’s established and CPUC-approved PSPS protocols and procedures, transmission lines in these areas remained energized.

The Utility has submitted electric incident reports to the CPUC indicating that:

- at approximately 9:19 p.m. Pacific Time on October 23, 2019, the Utility became aware of a transmission level outage on the Geysers #9 Lakeville 230 kV line when the line relayed and did not reclose;
- various generating facilities on the Geysers #9 Lakeville 230 kV line detected the disturbance and separated at approximately the same time;
- at approximately 9:21 p.m. Pacific Time, the PG&E Grid Control Center received a report that a fire had started in an area near transmission tower 001/006;
- at approximately 7:30 a.m. Pacific Time on October 24, 2019, a responding Utility troubleman patrolling the Geysers #9 Lakeville 230 kV line observed that Cal Fire had taped off the area around the base of transmission tower 001/006 in the area of the 2019 Kincade fire; and
- on site Cal Fire personnel brought to the troubleman’s attention what appeared to be a broken jumper on the same tower.

On July 16, 2020, Cal Fire issued a press release addressing the cause of the 2019 Kincade fire. The press release stated that Cal Fire has determined that “the Kincade Fire was caused by electrical transmission lines owned and operated by Pacific Gas and Electric (PG&E) located northeast of Geyserville. Tinder dry vegetation and strong winds combined with low humidity and warm temperatures contributed to extreme rates of fire spread.”

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Cal Fire also indicated that its investigative report has been forwarded to the Sonoma County District Attorney's Office, which is investigating the matter. On September 25, 2020, the Utility entered into a tolling agreement with the Sonoma County District Attorney's Office in which the Utility agreed to waive any applicable statute of limitations for violations related to the Kincade fire that would otherwise have expired on or about October 23, 2020, for a period of six months, until April 23, 2021. On February 24, 2021, the Sonoma County District Attorney's Office sent a search warrant to the Utility through its counsel in connection with the investigation. The Utility expects to produce documents and respond to other requests for information in connection with the investigation and the search warrant.

PG&E Corporation and the Utility are also conducting their own investigation into the cause of the 2019 Kincade fire. This investigation is preliminary, and PG&E Corporation and the Utility do not have access to all of the evidence in the possession of Cal Fire or other third parties.

Potential liabilities related to the 2019 Kincade fire depend on various factors, including but not limited to the cause of the fire, contributing causes of the fire (including alternative potential origins, weather- and climate-related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties, fines, or restitution that may be imposed by governmental entities.

If the Utility's facilities, such as its electric distribution and transmission lines, are judicially determined to be the substantial cause of the 2019 Kincade fire, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys' fees without having been found negligent. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Further, California courts have determined that the doctrine of inverse condemnation is applicable regardless of whether the CPUC ultimately allows recovery by the utility for any such costs. The CPUC may decide not to authorize cost recovery even if a court decision were to determine that the Utility is liable as a result of the application of the doctrine of inverse condemnation. (See "Loss Recoveries – Regulatory Recovery" below for further information regarding potential cost recovery related to the wildfires.)

In light of the current state of the law concerning inverse condemnation and the information currently available to PG&E Corporation and the Utility, including the information contained in the electric incident reports, Cal Fire's determination of the cause, and other information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2019 Kincade fire. Accordingly, PG&E Corporation and the Utility recorded a charge for potential losses in connection with the 2019 Kincade fire in the amount of \$625 million for the year ended December 31, 2020 (before available insurance).

The aggregate liability of \$625 million for claims in connection with the 2019 Kincade fire (before available insurance) corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses and is subject to change based on additional information. The \$625 million estimate does not include, among other things: (i) any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, (ii) any punitive damages, (iii) any amounts in respect of compensation claims by Federal or state agencies other than state fire suppression costs, (iv) evacuation costs or (v) any other amounts that are not reasonably estimable.

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The Utility believes it will continue to receive additional information from potential claimants as litigation or resolution efforts progress. Any such additional information may potentially allow PG&E Corporation and the Utility to refine such estimate and may result in changes to the accrual depending on the information provided.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of loss could be greater than \$625 million (before available insurance) but are unable to reasonably estimate the additional loss and the upper end of the range because, as described above, there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. If the liability for the 2019 Kincade fire were to exceed \$1.0 billion, it is possible the Utility would be eligible to make a claim to the Wildfire Fund under AB 1054 for such excess amount, subject to the 40% limitation on claims arising before emergence from bankruptcy. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of potential damages.

The process for estimating losses associated with potential claims related to the 2019 Kincade fire requires management to exercise significant judgment based on a number of assumptions and subjective factors, including the factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the potential financial impact of the 2019 Kincade fire may change.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Kincade fire in an aggregate amount of \$430 million. The Utility records insurance recoveries when it is deemed probable that recovery will occur, and the Utility can reasonably estimate the amount or its range. As of December 31, 2020, the Utility has recorded an insurance receivable for the full amount of the \$430 million. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries.

PG&E Corporation and the Utility have received data requests from the SED relating to the 2019 Kincade fire and have responded to all data requests received to date. The Sonoma County District Attorney's Office is currently investigating the fire and various other entities may also be investigating the fire. It is uncertain when the investigations will be complete.

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As of February 24, 2021, PG&E Corporation and the Utility are aware of 22 complaints on behalf of approximately 504 plaintiffs related to the 2019 Kincadee fire and expect that they may receive further such complaints. The complaints were filed in the California Superior Court for the County of Sonoma and the California Superior Court for the County of San Francisco and include claims based on multiple theories of liability, including inverse condemnation, negligence, violations of the Public Utilities Code, violations of the Health & Safety Code, premises liability, trespass, public nuisance and private nuisance. The plaintiffs in each action principally assert that PG&E Corporation's and the Utility's alleged failure to properly maintain, inspect and de-energize their transmission lines was the cause of the 2019 Kincadee fire. The plaintiffs seek damages that include property damage, economic loss, punitive damages, exemplary damages, attorneys' fees and other damages. On December 3, 2020, PG&E Corporation and the Utility filed a petition with the California Judicial Council to coordinate the litigation. The petition requests that the cases be coordinated in Sonoma County Superior Court. On December 18, 2020, certain plaintiffs filed a brief in support of PG&E Corporation's and the Utility's petition. On December 21, 2020, January 4, 2021 and January 27, 2021, certain plaintiffs filed briefs that supported coordination but requested that the cases be coordinated in San Francisco County Superior Court. On February 2, 2021, pursuant to authorization from the California Judicial Council, a judge of the Sonoma County Superior Court was assigned to serve as the coordination motion judge to decide whether the aforementioned actions should be coordinated and, if so, recommend where the coordinated proceeding should take place. A hearing is scheduled for April 2, 2021.

In addition to claims for property damage, business interruption, interest and attorneys' fees, PG&E Corporation and the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, punitive damages and other damages under other theories of liability, including if PG&E Corporation or the Utility were found to have been negligent.

2020 Zogg Fire

According to Cal Fire, on September 27, 2020, a wildfire began in the area of Zogg Mine Road and Jenny Bird Lane, north of Igo in Shasta County, California (the "2020 Zogg fire"), located in the service territory of the Utility. The Cal Fire Zogg fire Incident Update dated October 16, 2020, 3:08 p.m. Pacific Time (the "incident update"), indicated that the 2020 Zogg fire had consumed 56,338 acres. The incident update reported four fatalities and one injury. The incident update also indicated that 27 structures were damaged and 204 structures were destroyed. Of the 204 structures destroyed, 63 were single family homes, according to a damage inspection report available from the Shasta County Department of Resource Management.

On October 9, 2020, the Utility submitted an electric incident report to the CPUC indicating that:

- wildfire camera and satellite data on September 27, 2020 show smoke, heat or signs of fire in the area of Zogg Mine Road and Jenny Bird Lane between approximately 2:43 p.m. and 2:46 p.m. Pacific Time;
- according to Utility records, on September 27, 2020, a SmartMeter and a line recloser serving the area of Zogg Mine Road and Jenny Bird Lane reported alarms and other activity starting at approximately 2:40 p.m. until 3:06 p.m. Pacific Time when the line recloser de-energized a portion of the Girvan 1101 12 kV circuit, a distribution line that serves that area;
- the data currently available to the Utility do not establish the causes of the activity on the Girvan 1101 circuit or the locations of these causes;
- on October 9, 2020, Cal Fire informed the Utility that they had taken possession of Utility equipment as part of Cal Fire's ongoing investigation into the cause of the 2020 Zogg fire and allowed the Utility access to the area; and

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- Cal Fire has not issued a determination as to the cause.

The cause of the 2020 Zogg fire remains under investigation by Cal Fire, and PG&E Corporation and the Utility are cooperating with its investigation. PG&E Corporation and the Utility have received and are responding to data requests from the SED relating to the 2020 Zogg fire. The Shasta County District Attorney's Office is investigating the fire, and various other entities, which may include other law enforcement agencies, may also be investigating the fire. It is uncertain when any such investigations will be complete. PG&E Corporation and the Utility are also conducting their own investigation into the cause of the 2020 Zogg fire. This investigation is preliminary, and PG&E Corporation and the Utility do not have access to the evidence in the possession of Cal Fire or other third parties.

Potential liabilities related to the 2020 Zogg fire depend on various factors, including but not limited to the cause of the fire, contributing causes of the fire (including alternative potential origins, weather- and climate-related issues), the number, size and type of structures damaged or destroyed, the contents of such structures and other personal property damage, the number and types of trees damaged or destroyed, attorneys' fees for claimants, the nature and extent of any personal injuries, including the loss of lives, the amount of fire suppression and clean-up costs, other damages the Utility may be responsible for if found negligent, and the amount of any penalties, fines, or restitution that may be imposed by governmental entities.

Based on the current state of the law concerning inverse condemnation in California and the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including the information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2020 Zogg fire and accordingly recorded a pre-tax charge in the amount of \$275 million for the quarter ending December 31, 2020 (before available insurance). If the Utility's facilities, such as its electric distribution lines, are judicially determined to be the substantial cause of the Zogg fire, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest and attorneys' fees without having been found negligent. For more information regarding the inverse condemnation doctrine, see "2019 Kincade Fire" above.

The aggregate liability of \$275 million for claims in connection with the 2020 Zogg fire (before available insurance) corresponds to the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses, and is subject to change based on additional information. This \$275 million estimate does not include, among other things: (i) any amounts for potential penalties or fines that may be imposed by governmental entities on PG&E Corporation or the Utility, (ii) any punitive damages, (iii) any amounts in respect of compensation claims by federal, state, county and local government entities or agencies other than state fire suppression costs, or (iv) any other amounts that are not reasonably estimable.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of the loss will be greater than \$275 million and are unable to reasonably estimate the additional loss and the upper end of the range because, as described above, there are a number of unknown facts and legal considerations that may impact the amount of any potential liability, including the total scope and nature of claims that may be asserted against PG&E Corporation and the Utility. If the liability for the 2020 Zogg fire were to exceed \$1.0 billion, it is possible the Utility would be eligible to make a claim to the Wildfire Fund under AB 1054 for such excess amount. PG&E Corporation and the Utility intend to continue to review the available information and other information as it becomes available, including evidence in Cal Fire's possession, evidence from or held by other parties, claims that have not yet been submitted, and additional information about the nature and extent of personal and business property damages and losses, the nature, number and severity of personal injuries, and information made available through the discovery process. In particular, PG&E Corporation and the Utility have not had access to all of the evidence obtained by Cal Fire or other third parties.

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The process for estimating losses associated with potential claims related to the 2020 Zogg fire requires management to exercise significant judgment based on a number of assumptions and subjective factors, including the factors identified above and estimates based on currently available information and prior experience with wildfires. As more information becomes available, management estimates and assumptions regarding the potential financial impact of the 2020 Zogg fire may change.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the 2020 Zogg fire in an aggregate amount of \$867.5 million. The Utility records insurance recoveries when it is deemed probable that recovery will occur, and the Utility can reasonably estimate the amount or its range. As of December 31, 2020, the Utility has recorded an insurance receivable for \$219 million for probable insurance recoveries in connection with the 2020 Zogg fire, which equals the \$275 million probable loss estimate less an initial self-insured retention of \$60 million, plus \$4 million in legal fees incurred. PG&E Corporation and the Utility intend to seek full recovery for all insured losses. If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

As of February 24, 2021, PG&E Corporation and the Utility are aware of six complaints on behalf of approximately 240 plaintiffs related to the 2020 Zogg fire and expect that they may receive further such complaints. The complaints were filed in the California Superior Court for the County of Shasta and the California Superior Court for the County of San Francisco and include claims based on multiple theories of liability, including inverse condemnation, negligence, violations of the Public Utilities Code, violations of the Health & Safety Code, premises liability, trespass, public nuisance and private nuisance. The plaintiffs in each action principally assert that PG&E Corporation's and the Utility's alleged failure to properly maintain, inspect and de-energize their distribution lines was the cause of the 2020 Zogg fire. The plaintiffs seek damages that include wrongful death, property damage, economic loss, punitive damages, exemplary damages, attorneys' fees and other damages. On February 5, 2021, certain plaintiffs filed a petition with the California Judicial Council to coordinate five civil cases filed against the Utility and PG&E Corporation in the Superior Courts of Shasta and San Francisco counties. The petition requests that the cases be coordinated in San Francisco Superior Court.

In addition to claims for property damage, business interruption, interest and attorneys' fees, PG&E Corporation and the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, wrongful death and personal injury damages, punitive damages and other damages under other theories of liability, including if PG&E Corporation and the Utility were found to have been negligent.

Loss Recoveries

PG&E Corporation and the Utility have insurance coverage for liabilities, including wildfire. Additionally, there are several mechanisms that allow for recovery of costs from customers. Potential for recovery is described below. Failure to obtain a substantial or full recovery of costs related to wildfires or any conclusion that such recovery is no longer probable could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. In addition, the inability to recover costs in a timely manner could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

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Insurance

Insurance Coverage

PG&E Corporation and the Utility have liability insurance coverage for wildfire events in an amount of \$430 million (subject to an initial self-insured retention of \$10 million per occurrence) for the period from August 1, 2019 through July 31, 2020, and approximately \$1 billion in liability insurance coverage for non-wildfire events (subject to an initial self-insured retention of \$10 million per occurrence), comprised of \$520 million for the period from August 1, 2019 through July 31, 2020 and \$480 million for the period from September 3, 2019 through September 2, 2020. PG&E Corporation's and the Utility's cost of obtaining this wildfire and non-wildfire insurance coverage in place for the period of August 1, 2019 through September 2, 2020 is approximately \$212 million.

In July 2020, and through additional purchases in August 2020, the Utility renewed its liability insurance coverage for wildfire events in the amount of \$867.5 million (subject to an initial self-insured retention of \$60 million), comprised of \$825 million for the period of August 1, 2020 to July 31, 2021 and \$42.5 million in reinsurance for the period of July 1, 2020 through June 30, 2021. In addition, the Utility renewed its liability insurance coverage for non-wildfire events in the amount of \$700 million (subject to an initial self-insured retention of \$10 million) for the period from August 1, 2020 through July 31, 2021. PG&E Corporation's and the Utility's cost of obtaining this wildfire and non-wildfire coverage is approximately \$859 million. At December 31, 2020, PG&E Corporation and the Utility had prepaid insurance of \$536 million, reflected in Other current assets on the Consolidated Balance Sheets.

Various coverage limitations applicable to different insurance layers could result in material uninsured costs in the future depending on the amount and type of damages resulting from covered events.

In the Utility's 2020 GRC proceeding, the CPUC also approved a settlement agreement provision that allows the Utility to recover annual insurance costs for up to \$1.4 billion in general liability insurance coverage. An advice letter will be required for additional coverage purchased by the Utility in excess of \$1.4 billion in coverage.

The Utility will not be able to obtain any recovery from the Wildfire Fund for wildfire-related losses in any year that do not exceed the greater of \$1.0 billion in the aggregate and the amount of insurance coverage required under AB 1054. (See "Wildfire Fund under AB 1054" below.)

Insurance Receivable

PG&E Corporation and the Utility record a receivable for insurance recoveries when it is deemed probable that recovery of a recorded loss will occur. Through December 31, 2020, PG&E Corporation and the Utility recorded \$430 million for probable insurance recoveries in connection with the 2019 Kincadee fire, and \$219 million for probable insurance recoveries in connection with the 2020 Zogg fire. PG&E Corporation and the Utility have recovered all of the insurance for the 2015 Butte fire and the 2018 Camp fire. PG&E Corporation and the Utility have recovered all of the insurance except for \$25 million for the 2017 Northern California wildfires. These amounts reflect an assumption that the cause of each fire is deemed to be a separate occurrence under the insurance policies. PG&E Corporation and the Utility intend to seek full recovery for all insured losses.

If PG&E Corporation and the Utility are unable to recover the full amount of their insurance, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

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The balances for insurance receivables with respect to wildfires are included in Other accounts receivable in PG&E Corporation's and the Utility's Consolidated Balance Sheets:

Insurance Receivable (in millions)	2020 Zogg fire	2019 Kincadee fire	2018 Camp fire	2017 Northern California wildfires	2015 Butte fire	Total
Balance at December 31, 2019	\$ —	\$ —	\$ 1,380	\$ 808	\$ 50	\$ 2,238
Accrued insurance recoveries	219	430	—	—	—	649
Reimbursements	—	—	(1,380)	(783)	(50)	(2,213)
Balance at December 31, 2020	\$ 219	\$ 430	\$ —	\$ 25	\$ —	\$ 674

Regulatory Recovery

On June 21, 2018, the CPUC issued a decision granting the Utility's request to establish a WEMA to track specific incremental wildfire liability costs effective as of July 26, 2017. The decision does not grant the Utility rate recovery of any wildfire-related costs. Any such rate recovery would require CPUC authorization in a separate proceeding. The Utility may be unable to fully recover costs in excess of insurance, if at all. Rate recovery is uncertain; therefore, the Utility has not recorded a regulatory asset related to any wildfire claims costs. Even if such recovery is possible, it could take a number of years to resolve and a number of years to collect.

In addition, SB 901, signed into law on September 21, 2018, requires the CPUC to establish a CHT, directing the CPUC to limit certain disallowances in the aggregate, so that they do not exceed the maximum amount that the Utility can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service. SB 901 also authorizes the CPUC to issue a financing order that permits recovery, through the issuance of recovery bonds (also referred to as "securitization"), of wildfire-related costs found to be just and reasonable by the CPUC and, only for the 2017 Northern California wildfires, any amounts in excess of the CHT.

On January 10, 2019, the CPUC adopted an OIR, which establishes a process to develop criteria and a methodology to inform determinations of the CHT in future applications under Section 451.2(a) of the Public Utilities Code for recovery of costs related to the 2017 Northern California wildfires.

On July 8, 2019, the CPUC issued a decision in the CHT proceeding. The decision adopts a methodology to determine the CHT based on (1) the maximum additional debt that a utility can take on and maintain a minimum investment grade credit rating; (2) excess cash available to the utility; (3) a potential regulatory adjustment of 20% of the CHT or five percent of the total disallowed wildfire liabilities; and (4) an adjustment to preserve for ratepayers any tax benefits associated with the CHT. The decision also requires a utility to include proposed ratepayer protection measures to mitigate harm to ratepayers as part of an application under Section 451.2(b).

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Pursuant to SB 901 and the CPUC's methodology adopted in the CHT OIR, on April 30, 2020, the Utility filed an application with the CPUC seeking authorization for a post-emergence transaction to securitize \$7.5 billion of 2017 wildfire claims costs that is designed to not impact amounts billed to customers, with the proceeds used to pay or reimburse the Utility for the payment of wildfire claims costs associated with the 2017 Northern California wildfires. As a result of the proposed transaction, the Utility would retire \$6.0 billion of Utility debt and accelerate a \$592 million payment due to the Fire Victim Trust.

Failure to obtain a substantial or full recovery of costs related to wildfires could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows.

Wildfire-Related Derivative Litigation

Two purported derivative lawsuits alleging claims for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively, naming as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation and the Utility are named as nominal defendants. These lawsuits were consolidated by the court on February 14, 2018 and are denominated In Re California North Bay Fire Derivative Litigation. On April 13, 2018, the plaintiffs filed a consolidated complaint. After the parties reached an agreement regarding a stay of the derivative proceeding pending resolution of the tort actions described above and any regulatory proceeding relating to the 2017 Northern California wildfires, on April 24, 2018, the court entered a stipulation and order to stay. The stay was subject to certain conditions regarding the plaintiffs' access to discovery in other actions. On January 28, 2019, the plaintiffs filed a request to lift the stay for the purposes of amending their complaint to add allegations regarding the 2018 Camp fire. Prior to resolution of the plaintiffs' request to lift the stay, this matter was automatically stayed by PG&E Corporation's and the Utility's commencement of the Chapter 11 Cases, as discussed below. On November 12, 2020, the Trustee for the Fire Victim Trust filed a motion to intervene to substitute as the plaintiff in the matter. A case management conference is currently scheduled for March 18, 2021, at which time the court will also hear the motion to intervene.

On August 3, 2018, a third purported derivative lawsuit, entitled *Oklahoma Firefighters Pension and Retirement System v. Chew, et al.* (now captioned *Trotter v. PG&E Corp., et al.*), was filed in the U.S. District Court for the Northern District of California, naming as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation and the Utility. PG&E Corporation is named as a nominal defendant. The lawsuit alleges claims for breach of fiduciary duties and unjust enrichment as well as a claim under Section 14(a) of the federal Securities Exchange Act of 1934 alleging that PG&E Corporation's and the Utility's 2017 proxy statement contained misrepresentations regarding the companies' risk management and safety programs. On October 15, 2018, PG&E Corporation filed a motion to stay the litigation. Prior to the scheduled hearing on this motion, this matter was automatically stayed by PG&E Corporation's and the Utility's commencement of the Chapter 11 Cases, as discussed below. On December 14, 2020, the court entered a stipulation and order to substitute the Fire Victim Trust as the plaintiff. A case management conference is currently set for April 15, 2021.

On October 23, 2018, a fourth purported derivative lawsuit, entitled *City of Warren Police and Fire Retirement System v. Chew, et al.*, was filed in San Francisco County Superior Court, alleging claims for breach of fiduciary duty, corporate waste and unjust enrichment. It named as defendants certain current and former members of the Board of Directors and certain current and former officers of PG&E Corporation, and named PG&E Corporation as a nominal defendant. The plaintiff filed a request with the court seeking the voluntary dismissal of this matter without prejudice on January 18, 2019.

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On November 21, 2018, a fifth purported derivative lawsuit, entitled *Williams v. Earley, Jr., et al.* (now captioned *Trotter v. Earley, et al.*), was filed in federal court in San Francisco, alleging claims identical to those alleged in the *Oklahoma Firefighters Pension and Retirement System v. Chew, et al.* lawsuit listed above against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. This lawsuit includes allegations related to the 2017 Northern California wildfires and the 2018 Camp fire. This action was stayed by stipulation of the parties and order of the court on December 21, 2018, subject to resolution of the pending securities class action. On January 7, 2021, the court entered a stipulation and order to substitute the Fire Victim Trust as the plaintiff. A case management conference is currently set for April 15, 2021.

On December 24, 2018, a sixth purported derivative lawsuit, entitled *Bowlinger v. Chew, et al.* (now captioned *Trotter v. Chew, et al.*), was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. On February 5, 2019, the plaintiff filed a response to the notice asserting that the automatic stay did not apply to his claims. PG&E Corporation and the Utility accordingly filed a Motion to Enforce the Automatic Stay with the Bankruptcy Court as to the Bowlinger action, which was granted. On November 5, 2020, the court entered a stipulation and order to substitute the Fire Victim Trust as the plaintiff. On February 24, 2021, the Fire Victim Trust filed an amended complaint, alleging two causes of action for breach of fiduciary duty against certain former officers and directors. The first cause of action alleges breaches of fiduciary duty in connection with the 2017 Northern California wildfires, and the second cause of action alleges breaches of fiduciary duty in connection with the 2018 Camp fire. PG&E Corporation and the Utility are no longer named as nominal defendants. A case management conference is currently set for March 18, 2021.

On January 25, 2019, a seventh purported derivative lawsuit, entitled *Hagberg v. Chew, et al.*, was filed in San Francisco Superior Court, alleging claims for breach of fiduciary duty, abuse of control, corporate waste, and unjust enrichment in connection with the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. A case management conference is currently set for July 7, 2021.

On January 28, 2019, an eighth purported derivative lawsuit, entitled *Blackburn v. Meserve, et al.* (now captioned *Trotter v. Meserve, et al.*), was filed in federal court alleging claims for breach of fiduciary duty, unjust enrichment, and waste of corporate assets in connection with the 2017 Northern California wildfires and the 2018 Camp fire against certain current and former officers and directors, and naming PG&E Corporation as a nominal defendant. On January 8, 2021, the court entered a stipulation and order to substitute the Fire Victim Trust as the plaintiff. A case management conference is currently set for April 15, 2021.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed notices in each of these proceedings on February 1, 2019, reflecting that the proceedings were automatically stayed through the Effective Date pursuant to section 362(a) of the Bankruptcy Code. PG&E Corporation's and the Utility's rights with respect to the derivative claims asserted against former officers and directors of PG&E Corporation and the Utility were assigned to the Fire Victim Trust under the TCC RSA. The assignment became effective as of the Effective Date of the Plan.

The above purported derivative lawsuits were brought against the named defendants on behalf of PG&E Corporation and/or the Utility. As a result of the assignment of these claims to the Fire Victim Trust, any recovery based on these claims would be paid to the Fire Victim Trust. Any such recovery is limited to the extent of any director and officer insurance policy proceeds paid by any insurance carrier to reimburse PG&E Corporation and/or the Utility for amounts paid pursuant to their indemnification obligations in connection with such causes of action.

Securities Class Action Litigation

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Wildfire-Related Class Action

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California, naming PG&E Corporation and certain of its current and former officers as defendants, entitled *David C. Weston v. PG&E Corporation, et al.* and *Jon Paul Moretti v. PG&E Corporation, et al.*, respectively. The complaints alleged material misrepresentations and omissions related to, among other things, vegetation management and transmission line safety in various PG&E Corporation public disclosures. The complaints asserted claims under Section 10(b) and Section 20(a) of the federal Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, interest, attorneys' fees and other costs. Both complaints identified a proposed class period of April 29, 2015 to June 8, 2018. On September 10, 2018, the court consolidated both cases and the litigation is now denominated *In re PG&E Corporation Securities Litigation*. The court also appointed the Public Employees Retirement Association of New Mexico ("PERA") as lead plaintiff. The plaintiff filed a consolidated amended complaint on November 9, 2018. After the plaintiff requested leave to amend its complaint to add allegations regarding the 2018 Camp fire, the plaintiff filed a second amended consolidated complaint on December 14, 2018.

Due to the commencement of the Chapter 11 Cases, PG&E Corporation and the Utility filed a notice on February 1, 2019, reflecting that the proceedings were automatically stayed as to PG&E Corporation and the Utility pursuant to section 362(a) of the Bankruptcy Code. On February 15, 2019, PG&E Corporation and the Utility filed a complaint in Bankruptcy Court against the plaintiff seeking preliminary and permanent injunctive relief to extend the stay to the claims alleged against the individual officer defendants.

On February 22, 2019, a third purported securities class action was filed in the United States District Court for the Northern District of California, entitled *York County on behalf of the York County Retirement Fund, et al. v. Rambo, et al.* (the "York County Action"). The complaint names as defendants certain current and former officers and directors, as well as the underwriters of four public offerings of notes from 2016 to 2018. Neither PG&E Corporation nor the Utility is named as a defendant. The complaint alleges material misrepresentations and omissions in connection with the note offerings related to, among other things, PG&E Corporation's and the Utility's vegetation management and wildfire safety measures. The complaint asserts claims under Section 11 and Section 15 of the Securities Act of 1933, and seeks unspecified monetary relief, attorneys' fees and other costs, and injunctive relief. On May 7, 2019, the York County Action was consolidated with *In re PG&E Corporation Securities Litigation*.

On May 28, 2019, the plaintiffs in the consolidated securities actions filed a third amended consolidated class action complaint, which includes the claims asserted in the previously filed actions and names as defendants PG&E Corporation, the Utility, certain current and former officers and directors, and the underwriters. On August 28, 2019, the Bankruptcy Court denied PG&E Corporation's and the Utility's request to extend the stay to the claims against the officer, director, and underwriter defendants. On October 4, 2019, the officer, director, and underwriter defendants filed motions to dismiss the third amended complaint, which motions are currently under submission with the District Court.

Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims

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Claims against PG&E Corporation and the Utility relating to, among others, the three purported securities class actions (described above) that have been consolidated and denominated *In re PG&E Corporation Securities Litigation*, U.S. District Court for the Northern District of California, Case No. 18-03509, will be resolved pursuant to the Plan. As described above, these claims consist of pre-petition claims under the federal securities laws related to, among other things, allegedly misleading statements or omissions with respect to vegetation management and wildfire safety disclosures, and are classified into separate categories under the Plan, each of which is subject to subordination under the Bankruptcy Code. The first category of claims consists of pre-petition claims arising from or related to the common stock of PG&E Corporation (such claims, with certain other similar claims against PG&E Corporation, the “HoldCo Rescission or Damage Claims”). The second category of pre-petition claims, which comprises two separate classes under the Plan, consists of claims arising from debt securities issued by PG&E Corporation and the Utility (such claims, with certain other similar claims against PG&E Corporation and the Utility, the “Subordinated Debt Claims,” and together with the HoldCo Rescission or Damage Claims, the “Subordinated Claims”).

While PG&E Corporation and the Utility believe they have defenses to the Subordinated Claims, as well as insurance coverage that may be available in respect of the Subordinated Claims, these defenses may not prevail and any such insurance coverage may not be adequate to cover the full amount of the allowed claims. In that case, PG&E Corporation and the Utility will be required, pursuant to the Plan, to satisfy such claims as follows:

each holder of an allowed HoldCo Rescission or Damage Claim will receive a number of shares of common stock of PG&E Corporation equal to such holder’s HoldCo Rescission or Damage Claim Share (as such term is defined in the Plan); and

each holder of an allowed Subordinated Debt Claim will receive payment in full in cash.

PG&E Corporation and the Utility have been engaged in settlement efforts with respect to the Subordinated Claims. If the Subordinated Claims are not settled (with any such resolution being subject to the approval of the Bankruptcy Court), PG&E Corporation and the Utility expect that the Subordinated Claims will be resolved by the Bankruptcy Court in the claims reconciliation process and treated as described above under the Plan. Under the Plan, after the Effective Date, PG&E Corporation and the Utility have the authority to compromise, settle, object to, or otherwise resolve proofs of claim, and the Bankruptcy Court retains jurisdiction to hear disputes arising in connection with disputed claims. With respect to the Subordinated Claims, the claims reconciliation process may include litigation of the merits of such claims, including the filing of motions, fact discovery, and expert discovery. The total number and amount of allowed Subordinated Claims, if any, was not determined at the Effective Date. To the extent any such claims are allowed, the total amount of such claims could be material, and therefore could result in (a) the issuance of a material number of shares of common stock of PG&E Corporation with respect to allowed HoldCo Rescission or Damage Claims, and/or (b) the payment of a material amount of cash with respect to allowed Subordinated Debt Claims. There can be no assurance that such claims will not have a material adverse impact on PG&E Corporation’s and the Utility’s business, financial condition, results of operations, and cash flows.

Further, if shares are issued in respect of allowed HoldCo Rescission or Damage Claims, it may be determined that under the Plan, the Fire Victim Trust should receive additional shares of common stock of PG&E Corporation (assuming, for this purpose, that shares issued in respect of the HoldCo Rescission or Damage Claims were issued on the Effective Date).

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The named plaintiffs in the consolidated securities actions filed proofs of claim with the Bankruptcy Court on or before the bar date that reflect their securities litigation claims against PG&E Corporation and the Utility. On December 9, 2019, the lead plaintiff in the consolidated securities actions filed a motion seeking approval from the Bankruptcy Court to treat its proof of claim as a class proof of claim. On February 27, 2020, the Bankruptcy Court issued an order denying the motion, but extending the bar date for putative class members to file proofs of claim until April 16, 2020. On March 6, 2020, the lead plaintiff filed a notice of appeal regarding the denial of its motion. On May 15, 2020, the lead plaintiff filed the opening brief for its appeal. On June 15, 2020, PG&E Corporation and the Utility filed its brief in response. On June 29, 2020, the lead plaintiff filed its reply. No hearing date has been set.

On July 2, 2020, PERA filed a notice of appeal of the Confirmation Order to the District Court, solely to the extent of seeking review of that part of the Confirmation Order approving the Insurance Deduction (as defined in the Plan) with respect to the formula for the determination of the HoldCo Rescission or Damage Claims Share. On September 3, 2020, PERA filed its principal brief in support of the appeal. On October 5, 2020, PG&E Corporation and the Utility filed their response brief. PERA filed its reply brief on October 26, 2020. No hearing date has been set.

On September 1, 2020, PG&E Corporation and the Utility filed a motion (the “Securities Claims Procedures Motion”) with the Bankruptcy Court to approve procedures to allow for the resolution of the outstanding and unresolved Subordinated Claims, which motion, among other things, requests approval of certain information request procedures, standard and abbreviated mediation processes, and procedures with respect to the potential filing of omnibus claim objections with respect to the Subordinated Claims. PERA and a number of other parties filed objections to the Securities Claims Procedures Motion.

On September 28, 2020, PERA filed a second motion requesting the Bankruptcy Court exercise its discretion pursuant to Bankruptcy Rule 7023 to allow PERA to file a class proof of claim on behalf of the holders of Subordinated Claims (the “Renewed 7023 Motion”). The Bankruptcy Court set a briefing schedule that, among other things, (i) adjourned the hearing on the Securities Claims Procedures Motion to November 17, 2020, and (ii) established a briefing scheduled with respect to the Renewed 7023 Motion with a hearing on the motion also scheduled for November 17, 2020. PG&E Corporation and the Utility filed their objection to the Renewed 7023 Motion on October 29, 2020. On December 4, 2020, the Bankruptcy Court issued an oral decision approving PG&E Corporation’s and the Utility’s Securities Claims Procedures Motion and denying PERA’s Renewed 7023 Motion. On January 25, 2021, following a timeline set by the Bankruptcy Court as part of the oral decision to resolve any outstanding non-substantive objections to PG&E Corporation’s and the Utility’s proposed order granting the Securities Claims Procedures Motion, PG&E Corporation and the Utility filed a revised proposed order, which the Bankruptcy Court entered the same day. On January 26, 2021, the Bankruptcy Court entered a written order denying the Renewed 7023 Motion.

De-energization Class Action

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On October 25, 2019, a purported securities class action was filed in the United States District Court for the Northern District of California, entitled *Vataj v. Johnson et al.* The complaint named as defendants a current director and certain current and former officers of PG&E Corporation. Neither PG&E Corporation nor the Utility was named as a defendant. The complaint alleged materially false and misleading statements regarding PG&E Corporation's wildfire prevention and safety protocols and policies, including regarding the Utility's public safety power shutoffs, that allegedly resulted in losses and damages to holders of PG&E Corporation's securities. The complaint asserted claims under Section 10(b) and Section 20(a) of the federal Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, attorneys' fees and other costs. On February 3, 2020, the District Court granted a stipulation appointing Iron Workers Local 580 Joint Funds, Ironworkers Locals 40, 361 & 417 Union Security Funds and Robert Allustiarti co-lead plaintiffs and approving the selection of the plaintiffs' counsel, and further ordered the parties to submit a proposed schedule by February 13, 2020. On February 20, 2020, the District Court issued a scheduling order that required the amended complaint to be filed by April 17, 2020.

On April 17, 2020, the plaintiffs filed an amended complaint asserting the same claims. The amended complaint added PG&E Corporation and a former officer of PG&E Corporation as defendants, and no longer asserts claims against the other two officers of PG&E Corporation previously named in the action.

On May 15, 2020 the officer defendants filed their motion to dismiss in *Vataj*. On June 19, 2020, the lead plaintiff filed its opposition to the motion to dismiss. On July 10, 2020 the officer defendants filed their reply. In October 2020, the parties reached a settlement agreement in principle, and on October 29, 2020, filed a joint notice of settlement, informing the District Court that they have agreed in principle to settle the matter.

On February 16, 2021, plaintiffs filed a motion for preliminary approval of the settlement with the District Court, and the District Court issued an order terminating as moot the pending motion to dismiss, without prejudice. Pursuant to the settlement stipulation, subject to certain conditions: (1) PG&E Corporation will pay \$10 million into an interest-bearing escrow account within 14 days after the District Court's preliminary approval of the settlement; and (2) plaintiffs and the Settlement Class (as defined in the stipulation of settlement) will release the Released Persons (as defined the stipulation of settlement, including PG&E Corporation and the Utility, and each of their officers, directors, as well as the current and former officers named in both the original and amended complaints) from all claims that have been or could have been asserted by or on behalf of PG&E Corporation shareholders that relate to (a) allegations that were asserted or could have been asserted in either of the complaints in *Vataj*, and (b) investments in PG&E Corporation's stock during the relevant period specified in the stipulated settlement.

The settlement is subject to the District Court's approval and its terms may change as a result of the settlement approval process. The preliminary settlement approval hearing is currently scheduled for March 11, 2021. The final approval hearing is not yet scheduled. If the District Court approves the settlement and enters a judgment substantially in the form requested by the parties, the settlement will become effective when certain conditions specified in the settlement stipulation are satisfied, including the expiration of any right to appeal the judgment.

Indemnification Obligations

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To the extent permitted by law, PG&E Corporation and the Utility have obligations to indemnify directors and officers for certain events or occurrences while a director or officer is or was serving in such capacity, which indemnification obligations extend to the claims asserted against the directors and officers in the securities class action. PG&E Corporation and the Utility maintain directors' and officers' insurance coverage to reduce their exposure to such indemnification obligations. PG&E Corporation and the Utility have provided notice to their insurance carriers of the claims asserted in the wildfire-related securities class actions and derivative litigation, and are in communication with the carriers regarding the applicability of the directors and officers insurance policies to those matters. PG&E Corporation and the Utility additionally have potential indemnification obligations to the underwriters for the Utility's note offerings, pursuant to the underwriting agreements associated with those offerings. PG&E Corporation's and the Utility's indemnification obligations to the officers, directors and underwriters may be limited or affected by the Chapter 11 Cases.

District Attorneys' Offices Investigations

Following the 2018 Camp fire, the Butte County District Attorney's Office and the California Attorney General's Office opened a criminal investigation of the 2018 Camp fire. PG&E Corporation and the Utility were informed by the Butte County District Attorney's Office and the California Attorney General's Office that a grand jury had been empaneled in Butte County.

On March 17, 2020, the Utility entered into the Plea Agreement and Settlement (the "Plea Agreement") with the People of the State of California, by and through the Butte County District Attorney's office (the "People" and the "Butte DA," respectively) to resolve the criminal prosecution of the Utility in connection with the 2018 Camp fire. Subject to the terms and conditions of the Plea Agreement, the Utility agreed to plead guilty to 84 counts of involuntary manslaughter in violation of Penal Code section 192(b) and one count of unlawfully causing a fire in violation of Penal Code section 452, and to admit special allegations pursuant to Penal Code sections 452.1(a)(2), 452.1(a)(3) and 452.1(a)(4).

Per the Plea Agreement, the Utility was sentenced to pay the maximum total fine and penalty of approximately \$3.5 million. The Utility also agreed to pay \$500,000 to the Butte County District Attorney Environmental and Consumer Protection Fund to reimburse costs spent on the investigation of the 2018 Camp fire.

Simultaneous with entry into the Plea Agreement, the Utility has committed to spend up to \$15 million over five years to provide water to Butte County residents impacted by damage to the Utility's Miocene Canal caused by the 2018 Camp fire. In addition, the Utility has consented to the Butte District Attorney's consulting, sharing information with and receiving information from the Monitor overseeing the Utility's probation related to the San Bruno explosion through the expiration of the Utility's term of probation and in no event until later than January 31, 2022.

On June 16, 2020 through June 18, 2020, the Butte County Superior Court held proceedings at which the Utility pled guilty and was sentenced according to the terms of the Plea Agreement. On July 21, 2020, the Utility paid the \$3.5 million fine and penalty to the Butte County Superior Court and \$500,000 to the Butte County District Attorney Environmental and Consumer Protection Fund.

On January 15, 2021, the Butte County Superior Court held a brief hearing on the status of restitution, which involves distribution of funds from the Fire Victim Trust, which was established under the Company's Plan of Reorganization in Bankruptcy Court and is managed by a Trustee and a Claims Administrator. The Court continued the hearing to August 20, 2021 for a further update.

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Cal Fire announced that it had determined that “the Kincade Fire was caused by electrical transmission lines owned and operated by Pacific Gas and Electric (PG&E) located northeast of Geyserville. Tinder dry vegetation and strong winds combined with low humidity and warm temperatures contributed to extreme rates of fire spread.” Cal Fire also indicated that its investigative report has been forwarded to the Sonoma County District Attorney’s Office, which is currently conducting an investigation of the fire. On February 24, 2021, the Sonoma County District Attorney’s Office sent a search warrant to the Utility through its counsel in connection with the investigation. The Utility expects to produce documents and respond to other requests for information in connection with the investigation and the search warrant. For more information see “2019 Kincade Fire” above.

The Shasta County District Attorney’s Office is investigating the 2020 Zogg fire. See “2020 Zogg Fire” above for further information.

Additional investigations and other actions may arise out of the 2019 Kincade fire or the 2020 Zogg fire. The timing and outcome for resolution of any such investigations are uncertain.

SEC Investigation

On March 20, 2019, PG&E Corporation learned that the SEC’s San Francisco Regional Office was conducting an investigation related to PG&E Corporation’s and the Utility’s public disclosures and accounting for losses associated with the 2018 Camp fire, the 2017 Northern California wildfires and the 2015 Butte fire. PG&E Corporation and the Utility are unable to predict the timing and outcome of the investigation.

Wildfire Fund under AB 1054

On July 12, 2019, the California governor signed into law AB 1054, a bill which provides for the establishment of a statewide fund that will be available for eligible electric utility companies to pay eligible claims for liabilities arising from wildfires occurring after July 12, 2019 that are caused by the applicable electric utility company’s equipment, subject to the terms and conditions of AB 1054. Eligible claims are claims for third party damages resulting from any such wildfires, limited to the portion of such claims that exceeds the greater of (i) \$1.0 billion in the aggregate in any year and (ii) the amount of insurance coverage required to be in place for the electric utility company pursuant to Section 3293 of the Public Utilities Code, added by AB 1054.

Electric utility companies that draw from the Wildfire Fund will only be required to repay amounts that are determined by the CPUC in an application for cost recovery not to be just and reasonable, subject to a rolling three-year disallowance cap equal to 20% of the electric utility company’s transmission and distribution equity rate base. For the Utility, this disallowance cap is expected to be approximately \$2.7 billion for the three-year period starting in 2019, subject to adjustment based on changes in the Utility’s total transmission and distribution equity rate base. The disallowance cap is inapplicable in certain circumstances, including if the Wildfire Fund administrator determines that the electric utility company’s actions or inactions that resulted in the applicable wildfire constituted “conscious or willful disregard for the rights and safety of others,” or the electric utility company fails to maintain a valid safety certification. Costs that the CPUC determines to be just and reasonable will not need to be repaid to the Wildfire Fund, resulting in a draw-down of the Wildfire Fund.

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On August 23, 2019, the CPUC approved the Utility’s Initial Safety Certification, which under AB 1054 entitles the Utility to certain benefits, including eligibility for a cap on Wildfire Fund reimbursement and for a reformed prudent manager standard. The Utility satisfied the required elements for its Initial Safety Certificate, as follows: (i) the electrical corporation has an approved WMP, (ii) the electrical corporation is in good standing, which can be satisfied by the electrical corporation having agreed to implement the findings of its most recent safety culture assessment, if applicable, (iii) the electrical corporation has established a safety committee of its board of directors composed of members with relevant safety experience, and (iv) the electrical corporation has established board-of-director-level reporting to the CPUC on safety issues. Before the expiration of any current safety certification, the Utility must request a new safety certification for the following 12 months, which shall be issued within 90 days if the Utility has provided documentation that it has satisfied the requirements for the safety certification pursuant to Section 8389(e) of the Public Utilities Code, added by AB 1054. On July 29, 2020, the Utility submitted its application for a new safety certification. On January 14, 2021, the WSD approved the Utility’s 2020 application and issued the Utility’s 2020 Safety Certification pursuant to the requirements of AB 1054. The safety certification is separate from the CPUC’s enforcement authority and does not preclude the CPUC from pursuing remedies for safety or other applicable violations. The 2020 Safety Certification is valid for 12 months or until a timely request for a new safety certification is acted upon, whichever occurs later. On January 26, 2021, TURN filed with the CPUC a request for review of WSD’s issuance of the safety certification.

The Wildfire Fund and disallowance cap will be terminated when the amounts therein are exhausted. The Wildfire Fund is expected to be capitalized with (i) \$10.5 billion of proceeds of bonds supported by a 15-year extension of the Department of Water Resources charge to ratepayers, (ii) \$7.5 billion in initial contributions from California’s three IOU companies and (iii) \$300 million in annual contributions paid by California’s three IOU companies for at least a 10 year period. The contributions from the IOU companies will be effectively borne by their respective shareholders, as they will not be permitted to recover these costs from ratepayers. The costs of the initial and annual contributions are allocated among the three IOU companies pursuant to a “Wildfire Fund allocation metric” set forth in AB 1054 based on land area in the applicable utility’s service territory classified as high fire threat districts and adjusted to account for risk mitigation efforts. The Utility’s Wildfire Fund allocation metric is 64.2% (representing an initial contribution of approximately \$4.8 billion and annual contributions of approximately \$193 million). The Wildfire Fund will only be available for payment of eligible claims so long as there are sufficient funds remaining in the Wildfire Fund. Such funds could be depleted more quickly than expected, including as a result of claims made by California’s other participating electric utility companies.

AB 1054 also provides that the first \$5.0 billion expended in the aggregate by California’s three IOU companies on fire risk mitigation capital expenditures included in their respective approved WMPs will be excluded from their respective equity rate bases. The \$5.0 billion of capital expenditures will be allocated among the IOU companies in accordance with their Wildfire Fund allocation metrics (described above). The Utility’s allocation is \$3.21 billion. AB 1054 contemplates that such capital expenditures may be securitized through a customer charge.

On the Effective Date, having satisfied the conditions for the Utility’s initial participation in the Wildfire Fund, PG&E Corporation and the Utility contributed, in accordance with AB 1054, an initial contribution of approximately \$4.8 billion and first annual contribution of approximately \$193 million to the Wildfire Fund to secure participation of the Utility therein. SDG&E and Edison made their initial contributions to the Wildfire Fund in September 2019. On December 30, 2020, the Utility made its second annual contribution of \$193 million to the Wildfire Fund.

As of the Effective Date, the Wildfire Fund became available to the Utility to pay for eligible claims arising on or after the effective date of AB 1054, July 12, 2019, subject to a limit of 40% of the amount of allowed claims arising between the effective date of AB 1054 and the Effective Date of the Plan.

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For additional information on the Wildfire Fund, see Note 3 above.

NOTE 15: OTHER CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, penalties related to regulatory compliance, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. See "Purchase Commitments" below. PG&E Corporation and the Utility have financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the outcome of the following matters.

Enforcement Matters

U.S. District Court Matters and Probation

In connection with the Utility's probation proceeding, the United States District Court for the Northern District of California has the ability to impose additional probation conditions on the Utility. Additional conditions, if implemented, could be wide-ranging and would impact the Utility's operations, number of employees, costs and financial performance. Depending on the terms of these additional requirements, costs in connections with such requirements could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

CPUC and FERC Matters

Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire

On June 27, 2019, the CPUC issued the Wildfires OII to determine whether the Utility "violated any provision(s) of the California Public Utilities Code (PU Code), Commission General Orders (GO) or decisions, or other applicable rules or requirements pertaining to the maintenance and operation of its electric facilities that were involved in igniting fires in its service territory in 2017." On December 5, 2019, the assigned commissioner issued a second amended scoping memo and ruling that amended the scope of issues to be considered in this proceeding to include the 2018 Camp fire.

As previously disclosed, on December 17, 2019, the Utility, the SED of the CPUC, the CPUC's OSA, and CUE jointly submitted to the CPUC a proposed settlement agreement in connection with this proceeding and jointly moved for its approval.

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Pursuant to the settlement agreement, the Utility agreed to (i) not seek rate recovery of wildfire-related expenses and capital expenditures in future applications in the amount of \$1.625 billion, as specified below, and (ii) incur costs of \$50 million in shareholder-funded system enhancement initiatives as described further in the settlement agreement. The settlement agreement stipulates that no violations have been identified in the Tubbs fire. While, as a result of this finding, the settlement agreement does not prevent the Utility from seeking recovery of costs associated with the Tubbs fire through rates, the Utility has committed not to seek rate recovery for the Tubbs fire except through securitization. The amounts set forth in the table below include actual recorded costs and forecasted cost estimates as of the date of the settlement agreement for expenses and capital expenditures which the Utility has incurred or planned to incur to comply with its legal obligations to provide safe and reliable service. While actual costs incurred for certain cost categories are different than what was assumed in the settlement agreement, the Utility has recorded \$1.625 billion of the disallowed costs through December 31, 2020.

(in millions)

Description ⁽¹⁾	Expense	Capital	Total
Distribution Safety Inspections and Repairs Expense (FRMMA/WMPMA)	\$ 236	\$ —	\$ 236
Transmission Safety Inspections and Repairs Expense (TO) ⁽²⁾	433	—	433
Vegetation Management Support Costs (FHPMA)	36	—	36
2017 Northern California Wildfires CEMA Expense and Capital (CEMA)	82	66	148
2018 Camp Fire CEMA Expense (CEMA)	435	—	435
2018 Camp Fire CEMA Capital for Restoration (CEMA)	—	253	253
2018 Camp Fire CEMA Capital for Temporary Facilities (CEMA)	—	84	84
Total	\$ 1,222	\$ 403	\$ 1,625

(1) All amounts included in the table reflect actual recorded costs for 2019 and 2020.

(2) Transmission amounts are under the FERC's regulatory authority.

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated.

The Utility expects that the system enhancement spending pursuant to the settlement agreement will occur through 2025.

On April 20, 2020, the assigned commissioner issued a Decision Different adopting, with changes, the proposed modifications set forth in the request for review. The Decision Different (i) increases the amount of disallowed wildfire expenditures by \$198 million (as set forth in the POD); (ii) increases the amount of shareholder funding for System Enhancement Initiatives by \$64 million (as set forth in the POD); (iii) imposes a \$200 million fine but permanently suspends payment of the fine; and (iii) limits the tax savings that must be returned to ratepayers to those savings generated by disallowed operating expenditures. The Decision Different also denies all pending appeals of the POD and denies, in part, the Utility's motion requesting other relief. On April 30, 2020, the Utility submitted its comments on the Decision Different to the CPUC, accepting the modifications. The CPUC approved the Decision Different on May 7, 2020.

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The settlement agreement, as modified by the Decision Different, became effective upon: (i) approval by the CPUC in the Decision Different, (ii) following such approval by the CPUC, the June 20, 2020 approval of the Bankruptcy Court, and (iii) the July 1, 2020 effectiveness of the Plan.

As it relates to the additional \$198 million in disallowed costs as adopted in the Decision Different, the Utility has recorded charges of \$152 million primarily in WMPMA as of December 31, 2020 and intends to record the remaining charges of \$46 million in 2021.

On June 8, 2020, two parties filed separate applications for rehearing, the purpose of which was to challenge the CPUC's approval of the settlement agreement, as modified. On June 23, 2020, the Utility and CUE filed a joint response opposing the Applications for Rehearing. On December 3, 2020, the CPUC issued a decision denying the application for rehearing. On January 4, 2021, one party filed a petition for review of the CPUC decision with the California court of appeals. The Utility is unable to predict the timing and outcome of the petition.

Transmission Owner Rate Case Revenue Subject to Refund

The FERC determines the amount of authorized revenue requirements, including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. The Utility bills and records revenue based on the amounts requested in its rate case filing and records a reserve for its estimate of the amounts that are probable of refund. Rates subject to refund went into effect on March 1, 2017, March 1, 2018, and May 1, 2019 for TO18, TO19, and TO20, respectively.

On October 1, 2018, the ALJ issued an initial decision in the TO18 rate case and the Utility filed initial briefs on October 31, 2018, in response to the ALJ's recommendations. On October 15, 2020, the FERC issued an order that affirmed in part and reversed in part the initial decision. The order reopens the record for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning the FERC's revised ROE methodology adopted in the FERC Opinion No. 569-A, issued on May 21, 2020, that refined the methodology it established in Opinion No. 569 for setting the ROE that electric utilities are authorized to earn on electric transmission investments. Initial briefs were filed December 14, 2020 and reply briefs were filed February 12, 2021. In addition, the order approves depreciation rates that yield an estimated composite depreciation rate of 2.94% compared to the Utility's request of 3.25%. Further, the decision reduces forecasted capital, operations and maintenance, and cost of debt expense to actual costs incurred for the rate case period. Finally, the order upheld the initial decision's rejection of the Utility's direct assignment of common plant to FERC and required the allocation of all common plant between CPUC and FERC jurisdiction be based on operating and maintenance labor ratios. Application of the operating and maintenance labor rates would result in an allocation of 6.15% of common plant to FERC in comparison to 8.84% under the Utility's direct assignment method. The Utility filed a request for rehearing of certain aspects of the order, which was denied by the FERC on December 17, 2020. The Utility filed a petition for review of the order on February 11, 2021, and a separate petition for review was jointly filed the same day by two other parties. The ultimate outcome of the items for which the Utility requested rehearing could also impact the revenues recorded for the TO19 and TO20 periods.

On September 21, 2018, the Utility filed an all-party settlement with the FERC, which was approved by the FERC on December 20, 2018, in connection with TO19. As part of the settlement, the TO19 revenue requirement will be set at 98.85% of the revenue requirement for TO18 that will be determined upon issuance of a final unappealable decision in TO18.

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The Utility is unable to predict the timing or outcome of the FERC’s decisions in the TO18 proceeding.

Other Matters

PG&E Corporation and the Utility are subject to various claims and lawsuits that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under “Enforcement and Litigation Matters”) totaled \$144 million and \$116 million at December 31, 2020 and December 31, 2019, respectively. These amounts were included in LSTC at December 31, 2019 and were included in Other current liabilities at December 31, 2020. PG&E Corporation and the Utility do not believe it is reasonably possible that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows.

PSPS Class Action

On December 19, 2019, a complaint was filed in the United States Bankruptcy Court for the Northern District of California naming PG&E Corporation and the Utility. The plaintiff seeks certification of a class consisting of all California residents and business owners who had their power shut off by the Utility during the October 9, October 23, October 26, October 28, or November 20, 2019 power outages and any subsequent voluntary outages occurring during the course of litigation. The plaintiff alleges that the necessity for the October and November 2019 power shutoff events was caused by the Utility’s negligence in failing to properly maintain its electrical lines and surrounding vegetation. The complaint seeks up to \$2.5 billion in special and general damages, punitive and exemplary damages and injunctive relief to require the Utility to properly maintain and inspect its power grid. PG&E Corporation and the Utility believe the allegations are without merit and intend to defend this lawsuit vigorously.

On January 21, 2020, PG&E Corporation and the Utility filed a motion to dismiss the complaint or in the alternative strike the class action allegations. The motion to dismiss and strike was heard by the Bankruptcy Court on March 10, 2020, and on April 3, 2020, the Bankruptcy Court entered an order dismissing the action without leave to amend, finding that the action was preempted under the California Public Utilities Code.

On March 30, 2020, the Bankruptcy Court issued an opinion granting the Utility's motion to dismiss this class action. The court held that the plaintiff’s class action claims are preempted as a matter of law by section 1759 of the California Public Utilities Code and thus the plaintiffs could not pursue civil damages. The court stated that “any claim for damages caused by PSPS events approved by the CPUC, even if based on pre-existing events that may or may not have contributed to the necessity of the PSPS events, would interfere with the CPUC’s policy-making decisions.”

On April 6, 2020, the plaintiff filed a notice of appeal of the Bankruptcy Court decision dismissing the complaint. The plaintiff has elected to have the appeal heard by the District Court, rather than the Bankruptcy Appellate Panel. The plaintiff filed a designation of the record and statement of the issues on April 20, 2020.

On June 8, 2020, the plaintiff filed its opening brief with the District Court. The Utility filed its opposition brief on July 6, 2020. The plaintiff’s reply brief was filed on August 4, 2020 with a request for oral argument. On October 20, 2020, the District Court denied the plaintiff’s request for oral argument and stated that if it wants to hear oral argument, it will inform the parties and schedule a hearing.

The Utility is unable to determine the timing and outcome of this proceeding.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

GT&S Capital Expenditures 2011-2014

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base \$696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed \$120 million of that amount and ordered that the remaining \$576 million be subject to a review of reasonableness to be conducted, or overseen, by the CPUC staff. The review was completed on June 1, 2020 and did not result in any additional disallowances. The report certified \$512 million for future recovery. The difference between the certified amount and the \$576 million previously disallowed is primarily a result of differences between capital expenditures forecasted in the 2015 GT&S rate case and recorded capital expenditures.

On July 31, 2020, the Utility filed an application seeking recovery of revenue requirements on the \$512 million of capital expenditures retroactive to January 1, 2015. On October 16, 2020, the assigned commissioner issued a scoping memo establishing the scope and schedule for the proceeding. On January 20, 2021, the Utility provided supplemental testimony and supporting working papers addressing the reasonableness of the capital expenditures. The scoping memo calls for the issuance of a proposed decision in the fourth quarter of 2021.

The Utility is unable to determine the timing and outcome of this proceeding.

CZU Lightning Complex Fire Notices of Violation

Several governmental entities have raised concerns regarding the Utility's emergency response to the 2020 CZU Lightning Complex fire, including Cal Fire alleging violations of Public Resource Code sections related to timber harvest regulations and Forest Practice Rules, the California Coastal Commission alleging violations of the Coastal Act related to unpermitted development in the coastal zone, the Central Coast Regional Water Quality Control Board alleging unpermitted discharge to waters, and the Santa Cruz County Board of Supervisors adopting a resolution to file a complaint with the CPUC. The concerns include potential environmental impacts related to erosion and sedimentation from hazard tree removal and access road use, work in sensitive habitats, and the management of wood debris. The Coastal Commission issued a Notice of Violation letter to the Utility on November 20, 2020, the Central Coast Regional Water Quality Control Board issued a Notice of Violation letter on December 15, 2020, Cal Fire has issued five Notices of Violation through February 8, 2021, and Santa Cruz County filed a complaint with the CPUC on January 25, 2021. The Utility continues to work with all agencies, as well as Santa Cruz County, to resolve any outstanding issues.

Based on the information currently available, PG&E Corporation and the Utility believe it is probable that a liability has been incurred. The Utility is unable to reasonably estimate the amount or range of potential penalties that could be incurred given the number of factors that can be considered in determining penalties. PG&E Corporation and the Utility do not believe that the resolution of these matters will have a material impact on their financial condition, results of operations, or cash flows. Violations can result in penalties, remediation and other relief.

Environmental Remediation Contingencies

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Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities requires significant judgment. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable, and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Key factors that inform the development of estimated costs include site feasibility studies and investigations, applicable remediation actions, operations and maintenance activities, post-remediation monitoring, and the cost of technologies that are expected to be approved to remediate the site. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is comprised of the following:

(in millions)	Balance at	
	December 31, 2020	December 31, 2019
Topock natural gas compressor station	\$ 303	\$ 362
Hinkley natural gas compressor station	132	138
Former manufactured gas plant sites owned by the Utility or third parties ⁽¹⁾	659	568
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites ⁽²⁾	111	101
Fossil fuel-fired generation facilities and sites ⁽³⁾	96	106
Total environmental remediation liability	\$ 1,301	\$ 1,275

(1) Primarily driven by the following sites: San Francisco Beach Street, Vallejo, Napa, and San Francisco East Harbor.

(2) Primarily driven by Geothermal landfill and Shell Pond site.

(3) Primarily driven by the San Francisco Potrero Power Plant.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the Environmental Protection Agency under the Federal Resource Conservation and Recovery Act in addition to other state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors the environmental requirements on an ongoing basis and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at December 31, 2020, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans, the Utility's time frame for remediation, and unanticipated claims filed against the Utility. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition, and cash flows during the period in which they are recorded. At December 31, 2020, the Utility expected to recover \$986 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018 and will continue for several years. The Utility's undiscounted future costs associated with the Topock site may increase by as much as \$216 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. A draft background report was received in January 2020 and is expected to be finalized in 2021. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as \$138 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as \$460 million if the extent of contamination or necessary remediation at currently identified MGP sites is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

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Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as \$67 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as \$43 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL, a mutual insurer owned by utilities with nuclear facilities, and EMANI, covering nuclear or non-nuclear events at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3.

NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon. NEIL provides property damage and business interruption coverage of up to \$3.2 billion per nuclear incident and \$2.7 billion per non-nuclear incident for Diablo Canyon. For Humboldt Bay Unit 3, NEIL provides up to \$50 million of coverage for nuclear and non-nuclear property damages.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Through NEIL, there is up to \$3.2 billion available to the membership to cover this exposure. This coverage amount is shared by all NEIL members and applies to all terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL.

In addition to the nuclear insurance the Utility maintains through NEIL, the Utility also is a member of EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at Diablo Canyon. EMANI provides an additional \$200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, the maximum aggregate annual retrospective premium obligation for the Utility would be approximately \$43 million. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately \$4 million.

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Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to approximately \$13.8 billion. The Utility purchases the maximum available public liability insurance of \$450 million for Diablo Canyon. The balance of the \$13.8 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to \$275 million per nuclear incident under this loss sharing program, with payments in each year limited to a maximum of \$41 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of \$450 million per incident. In addition, the Utility has approximately \$53 million of liability insurance for Humboldt Bay Unit 3 and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents for Humboldt Bay Unit 3, covering liabilities in excess of the \$53 million in liability insurance.

Diablo Canyon Outages

Diablo Canyon Unit 2 has experienced four outages between July 2020 and February 24, 2021, each due or related to malfunctions within the main generator associated with excessive vibrations. Additional inspections and replacement of a redesigned component of the generator are expected to occur during Unit 2's planned spring 2021 refueling outage. The affected component is part of the secondary system and does not involve a risk of release of radioactive material into the environment. The Utility is working with the vendor that supplied the affected component to understand the root cause and to develop appropriate corrective actions.

If additional shutdowns occur in the future, or if the planned refueling outage is extended due to the inspections and replacement of the affected component, the Utility may incur incremental costs or forgo additional power market revenues. The Utility will also be subject to a review of the reasonableness of its actions before the CPUC.

Diablo Canyon carries property damage and outage insurance issued by NEIL. The Utility has notified NEIL of its potential claims for loss recovery.

The Utility is unable to reasonably estimate the occurrence or length of future outages, the cost to repair the generator, the loss of power market revenues, or the results of a reasonableness review by the CPUC.

Purchase Commitments

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2020:

(in millions)	Power Purchase Agreements			Natural Gas	Nuclear Fuel	Total
	Renewable Energy	Conventional Energy	Other			
2021	\$ 2,270	\$ 582	\$ 65	\$ 466	\$ 64	\$ 3,447
2022	2,042	511	62	191	54	2,860

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NOTES TO FINANCIAL STATEMENTS (Continued)			

2023	1,997	223	61	158	49	2,488
2024	1,972	72	61	151	47	2,303
2025	1,962	70	61	151	—	2,244
Thereafter	21,335	281	41	184	—	21,841
Total purchase commitments	\$ 31,578	\$ 1,739	\$ 351	\$ 1,301	\$ 214	\$ 35,183

Third-Party Power Purchase Agreements

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery.

Renewable Energy Power Purchase Agreements. In order to comply with California's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement. The Utility's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2020, renewable energy contracts expire at various dates between 2021 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2020, these power purchase agreements expire at various dates between 2021 and 2033.

Other Power Purchase Agreements. The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. As of December 31, 2020, QF contracts in operation expire at various dates between 2021 and 2049. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The net costs incurred for all power purchases and electric capacity amounted to \$2.9 billion in 2020, \$3.0 billion in 2019, and \$3.1 billion in 2018.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2021 and 2026. In addition, the Utility has contracted for natural gas storage services in northern California to more reliably meet customers' loads.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts with terms of less than 1 year, amounted to \$0.8 billion in 2020, \$0.9 billion in 2019, and \$0.6 billion in 2018.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2021 and 2024 and are intended to ensure long-term nuclear fuel supply. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to \$111 million in 2020, \$74 million in 2019, and \$73 million in 2018.

Other Commitments

PG&E Corporation and the Utility have other commitments primarily related to office facilities and land leases, which expire at various dates between 2021 and 2052. At December 31, 2020, the future minimum payments related to these commitments were as follows:

(in millions)	Other Commitments
2021	\$ 40
2022	30
2023	46
2024	65
2025	60
Thereafter	2,924
Total minimum lease payments	\$ 3,165

Payments for other commitments amounted to \$45 million in 2020, \$48 million in 2019, and \$43 million in 2018. Certain office facility leases contain escalation clauses requiring annual increases in rent. The rents may increase by a fixed amount each year, a percentage of the base rent, or the consumer price index. There are options to extend these leases for one to five years.

One of these commitments is treated as a financing lease. At December 31, 2020 and 2019, net financing leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were \$7 million and \$9 million including accumulated amortization of \$11 million and \$9 million, respectively. The present value of the future minimum lease payments due under these agreements included \$2 million and \$2 million in Current Liabilities and \$5 million and \$7 million in Noncurrent Liabilities on the Consolidated Balance Sheet, at December 31, 2020 and 2019, respectively.

Oakland Headquarters Lease

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NOTES TO FINANCIAL STATEMENTS (Continued)			

On June 5, 2020, the Utility entered into an Agreement to Enter Into Lease and Purchase Option (the “Agreement”) with TMG Bay Area Investments II, LLC (“TMG”). The Agreement provides that, contingent on (i) entry of an order by the Bankruptcy Court authorizing the Utility to enter into the Agreement and the Lease Agreement (as defined below), subject to certain conditions, and (ii) acquisition of the Lakeside Building by BA2 300 Lakeside LLC (“Landlord”), a wholly owned subsidiary of TMG, the Utility and Landlord will enter into an office lease agreement (the “Lease Agreement”) for approximately 910,000 rentable square feet of space within the building located at the Lakeside Building to serve as the Utility’s principal administrative headquarters (the “Lease”). On June 9, 2020, PG&E Corporation and the Utility filed a motion with the Bankruptcy Court authorizing them to enter into the Agreement and grant related relief. The Bankruptcy Court entered an order approving the motion on June 24, 2020.

Pursuant to the terms of the Agreement, concurrent with the Landlord’s acquisition of the Lakeside Building, on October 23, 2020, the Utility and the Landlord entered into the Lease, and the Utility issued to Landlord (i) an option payment letter of credit in the amount of \$75 million, and (ii) and a lease security letter of credit in the amount of \$75 million.

The term of the Lease will begin on or about March 1, 2022. The Lease term will expire 34 years and 11 months after the commencement date, unless earlier terminated in accordance with the terms of the Lease. In addition to base rent, the Utility will be responsible for certain costs and charges specified in the Lease, including insurance costs, maintenance costs and taxes.

The Lease requires the Landlord to pursue approvals to subdivide the real estate it owns surrounding the Lakeside Building to create a separate legal parcel that contains the Lakeside Building (the “Property”) that can be sold to the Utility. The Lease grants to the Utility an option to purchase the Property, following such subdivision, at a price of \$892 million, subject to certain adjustments (the “Purchase Price”). The Purchase Price would not be paid until 2023.

In connection with entry into the Agreement, the Utility intends to sell its current office space generally located at 77 Beale Street, 215 Market Street, 245 Market Street and 50 Main Street, San Francisco, California 94105, and associated properties owned by the Utility (“SFGO”). Any sale of the SFGO would be subject to approval by the CPUC. On September 30, 2020, the Utility filed an application with the CPUC seeking authorization to sell the SFGO.

At December 31, 2020, the Lease Agreement had no impact on PG&E Corporation’s and the Utility’s Consolidated Financial Statements.

NOTE 16: SUBSEQUENT EVENTS

Sale of Transmission Tower Wireless Licenses

On February 16, 2021, the Utility granted to a subsidiary of SBA Communications Corporation (such subsidiary, “SBA”) an exclusive license enabling SBA to sublicense and market wireless communications equipment attachment locations (“Cell Sites”) on more than 700 of the Utility’s electric transmission towers, telecommunications towers, monopoles, buildings or other structures (collectively, the “Effective Date Towers”) to wireless telecommunication carriers (“Carriers”) for attachment of wireless communications equipment, as contemplated by a Master Transaction Agreement (the “Transaction Agreement”) dated February 2, 2021, between the Utility and SBA. Pursuant to the Transaction Agreement, the Utility also assigned to SBA license agreements between the Utility and Carriers for substantially all of the existing Cell Sites on the Effective Date Towers.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

The exclusive license was granted pursuant to a Master Multi-Site License Agreement (the "License Agreement") between the Utility and SBA. The term of the License Agreement is for 100 years. The Utility has the right to terminate the license for individual Cell Sites for certain regulatory or utility operational reasons, with a corresponding payment to SBA. Pursuant to the License Agreement, SBA is entitled to the sublicensing revenue generated by new sublicenses of Cell Sites on the Effective Date Towers, subject to the Utility's right to a percentage of such sublicensing revenue.

In exchange for the exclusive license and entry into the License Agreement, SBA agreed to pay the Utility a purchase price of \$973 million, subject to customary adjustments. SBA paid the Utility \$954 million of such purchase price at the closing pursuant to the Transaction Agreement, which also contemplates the post-closing assignment of additional specified Cell Sites to SBA upon the satisfaction of certain terms and conditions, for which SBA will make additional purchase price payments to the Utility. The closing settlement also reflected an adjustment for an estimated amount of payments received by the Utility from Carriers in the pre-closing period that are allocable to licenses in the post-closing period, resulting in initial cash proceeds of \$945 million. The purchase price is subject to further adjustment pursuant to the terms of the Transaction Agreement.

The Utility and SBA also entered into a Master Transmission Tower Site License Agreement (the "Tower Site Agreement"), pursuant to which SBA received the exclusive rights to sublicense and market potential additional attachment locations on approximately 28,000 of the Utility's other electric transmission towers to Carriers for attachment of wireless communications equipment. The Tower Site Agreement provides for a split of license fees from Carriers between the Utility and SBA. The Tower Site Agreement has a licensing period of up to 15 years, depending on SBA's achievement of certain performance metrics, and any sites licensed during such licensing period will continue to be subject to the Tower Site Agreement for the same term as the License Agreement.

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				(986,708)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				597,861
3	Preceding Quarter/Year to Date Changes in Fair Value				1,406,636
4	Total (lines 2 and 3)				2,004,497
5	Balance of Account 219 at End of Preceding Quarter/Year				1,017,789
6	Balance of Account 219 at Beginning of Current Year				1,017,789
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				698,516
8	Current Quarter/Year to Date Changes in Fair Value				(6,337,523)
9	Total (lines 7 and 8)				(5,639,007)
10	Balance of Account 219 at End of Current Quarter/Year				(4,621,218)

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			(986,708)		
2			597,861		
3			1,406,636		
4			2,004,497	(7,621,767,673)	(7,619,763,176)
5			1,017,789		
6			1,017,789		
7			698,516		
8			(6,337,523)		
9			(5,639,007)	410,958,488	405,319,481
10			(4,621,218)		

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)	80,418,017,616	58,872,467,824
4	Property Under Capital Leases	1,754,428,569	1,656,610,189
5	Plant Purchased or Sold	-396,482	-345,946
6	Completed Construction not Classified	17,147,244,936	10,194,558,560
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	99,319,294,639	70,723,290,627
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,758,242,099	1,929,075,179
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	102,077,536,738	72,652,365,806
14	Accum Prov for Depr, Amort, & Depl	41,313,895,992	29,945,181,598
15	Net Utility Plant (13 less 14)	60,763,640,746	42,707,184,208
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	40,512,834,588	29,873,867,093
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	8,558,277	
21	Amort of Other Utility Plant	792,503,127	71,314,505
22	Total In Service (18 thru 21)	41,313,895,992	29,945,181,598
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)	41,313,895,992	29,945,181,598

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
15,367,031,678				6,178,518,114	3
				97,818,380	4
104,025				-154,561	5
6,262,497,804				690,188,572	6
					7
21,629,633,507				6,966,370,505	8
					9
					10
383,098,848				446,068,072	11
					12
22,012,732,355				7,412,438,577	13
8,582,095,171				2,786,619,223	14
13,430,637,184				4,625,819,354	15
					16
					17
8,573,219,359				2,065,748,136	18
					19
8,558,277					20
317,536				720,871,086	21
8,582,095,172				2,786,619,222	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
8,582,095,172				2,786,619,222	33

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	134,676,856	120,482,320
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	134,676,856	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	397,424,984	76,306,720
10	SUBTOTAL (Total 8 & 9)	397,424,984	
11	Spent Nuclear Fuel (120.4)	2,566,969,545	114,255,938
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,743,468,286	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	355,603,099	
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 End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
	76,306,720	178,852,456	3
			4
			5
		178,852,456	6
			7
			8
	114,255,937	359,475,767	9
		359,475,767	10
		2,681,225,483	11
			12
	-109,539,888	2,853,008,174	13
		366,545,532	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

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

Cost of fuel inserted into reactor during 2020; cost transferred from Nuclear Fuel in Process to Nuclear Fuel in Reactor.

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

Cost of spent fuel transferred from Nuclear Fuel in Reactor to Spent Nuclear Fuel in 2020.

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	139,001,479	182,958,569
4	(303) Miscellaneous Intangible Plant	7,142,779	6,332,789
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	146,144,258	189,291,358
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,644,205	
9	(311) Structures and Improvements	113,965,827	38,162
10	(312) Boiler Plant Equipment	279,931,336	3,049,383
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	257,633,721	
13	(315) Accessory Electric Equipment	52,625,551	
14	(316) Misc. Power Plant Equipment	28,348,904	
15	(317) Asset Retirement Costs for Steam Production	96,102,035	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	837,251,579	3,087,545
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	22,726,561	
19	(321) Structures and Improvements	1,092,063,773	14,891,643
20	(322) Reactor Plant Equipment	3,596,796,769	6,416,319
21	(323) Turbogenerator Units	1,211,169,500	6,933,358
22	(324) Accessory Electric Equipment	867,719,122	8,811,574
23	(325) Misc. Power Plant Equipment	1,171,280,933	26,206,125
24	(326) Asset Retirement Costs for Nuclear Production	3,364,966,683	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	11,326,723,341	63,259,019
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	44,055,068	392,696
28	(331) Structures and Improvements	536,639,786	7,974,357
29	(332) Reservoirs, Dams, and Waterways	2,141,455,482	71,705,740
30	(333) Water Wheels, Turbines, and Generators	1,050,584,857	48,814,854
31	(334) Accessory Electric Equipment	310,319,133	12,597,151
32	(335) Misc. Power PLant Equipment	119,265,133	16,772,404
33	(336) Roads, Railroads, and Bridges	97,960,943	559,858
34	(337) Asset Retirement Costs for Hydraulic Production	7,200,427	248,182,125
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	4,307,480,829	406,999,185
36	D. Other Production Plant		
37	(340) Land and Land Rights	19,207,870	
38	(341) Structures and Improvements	211,013,036	555,508
39	(342) Fuel Holders, Products, and Accessories	11,473,459	
40	(343) Prime Movers	227,980,319	670,852
41	(344) Generators	353,878,262	119,389
42	(345) Accessory Electric Equipment	214,406,078	1,306,417
43	(346) Misc. Power Plant Equipment	98,908,747	3,000,847
44	(347) Asset Retirement Costs for Other Production		46,948,130
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,136,867,771	52,601,143
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	17,608,323,520	525,946,892

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
3,265,747		-2,927	318,691,374	3
			13,475,568	4
3,265,747		-2,927	332,166,942	5
				6
				7
		-43,799	8,600,406	8
			114,003,989	9
			282,980,719	10
				11
			257,633,721	12
			52,625,551	13
			28,348,904	14
			96,102,035	15
		-43,799	840,295,325	16
				17
			22,726,561	18
1,945,744			1,105,009,672	19
9,759,682			3,593,453,406	20
2,356,980			1,215,745,878	21
5,503,060			871,027,636	22
7,406,702			1,190,080,356	23
			3,364,966,683	24
26,972,168			11,363,010,192	25
				26
323,271			44,124,493	27
4,019,832			540,594,311	28
8,109,801			2,205,051,421	29
20,406,830			1,078,992,881	30
9,706,211			313,210,073	31
2,076,346			133,961,191	32
533,938			97,986,863	33
			255,382,552	34
45,176,229			4,669,303,785	35
				36
255			19,207,615	37
			211,568,544	38
			11,473,459	39
			228,651,171	40
			353,997,651	41
			215,712,495	42
			101,909,594	43
			46,948,130	44
255			1,189,468,659	45
72,148,652		-43,799	18,062,077,961	46

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	280,372,715	9,064,196
49	(352) Structures and Improvements	493,641,027	-9,932,518
50	(353) Station Equipment	6,970,636,084	664,838,833
51	(354) Towers and Fixtures	993,433,125	58,242,335
52	(355) Poles and Fixtures	1,666,570,377	300,875,946
53	(356) Overhead Conductors and Devices	1,983,526,864	214,606,791
54	(357) Underground Conduit	512,801,262	3,467,536
55	(358) Underground Conductors and Devices	276,592,706	12,454,766
56	(359) Roads and Trails	107,222,352	26,469,203
57	(359.1) Asset Retirement Costs for Transmission Plant	3,756,679	3,966,507
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	13,288,553,191	1,284,053,595
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	181,121,477	3,840,745
61	(361) Structures and Improvements	323,717,422	5,427,152
62	(362) Station Equipment	3,710,334,305	251,924,503
63	(363) Storage Battery Equipment	31,646,931	2,913,527
64	(364) Poles, Towers, and Fixtures	5,387,044,284	1,147,709,098
65	(365) Overhead Conductors and Devices	5,125,782,513	370,276,908
66	(366) Underground Conduit	3,133,089,997	164,932,642
67	(367) Underground Conductors and Devices	5,043,166,504	311,513,623
68	(368) Line Transformers	4,111,052,424	440,941,887
69	(369) Services	3,591,993,628	176,524,339
70	(370) Meters	1,249,604,097	70,861,919
71	(371) Installations on Customer Premises	29,313,948	129,307
72	(372) Leased Property on Customer Premises	895,448	
73	(373) Street Lighting and Signal Systems	264,203,617	5,294,325
74	(374) Asset Retirement Costs for Distribution Plant	14,974,899	10,308,746
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	32,197,941,494	2,962,598,721
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	424,632	
87	(390) Structures and Improvements	12,683,086	9,807,920
88	(391) Office Furniture and Equipment	15,278,863	186,428
89	(392) Transportation Equipment		
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	156,770,157	18,103,573
92	(395) Laboratory Equipment	12,102,476	99,111
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	441,601,021	77,988,993
95	(398) Miscellaneous Equipment	157,070,312	-106,478,132
96	SUBTOTAL (Enter Total of lines 86 thru 95)	795,930,547	-292,107
97	(399) Other Tangible Property	468,499,422	
98	(399.1) Asset Retirement Costs for General Plant	6,888,838	687,257
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,271,318,807	395,150
100	TOTAL (Accounts 101 and 106)	64,512,281,270	4,962,285,716
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	-5,412	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	64,512,286,682	4,962,285,716

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
		-5,896,750	283,540,161	48
330,319			483,378,190	49
58,860,691		19,695,451	7,596,309,677	50
5,305,493		1,472,217	1,047,842,184	51
7,541,998			1,959,904,325	52
13,198,979		6,675,897	2,191,610,573	53
			516,268,798	54
275,334			288,772,138	55
480,785		-46,838	133,163,932	56
			7,723,186	57
85,993,599		21,899,977	14,508,513,164	58
				59
53		-144,925	184,817,244	60
			329,144,574	61
47,621,797	158,692	-19,695,451	3,895,100,252	62
			34,560,458	63
45,241,572		-2,086,303	6,487,425,507	64
87,761,020			5,408,298,401	65
358,641		6,572,760	3,304,236,758	66
14,120,017			5,340,560,110	67
37,369,167			4,514,625,144	68
6,598,628			3,761,919,339	69
11,601,443			1,308,864,573	70
			29,443,255	71
			895,448	72
611,337			268,886,605	73
			25,283,645	74
251,283,675	158,692	-15,353,919	34,894,061,313	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			424,632	86
			22,491,006	87
256,824			15,208,467	88
				89
				90
11,991			174,861,739	91
274,241			11,927,346	92
				93
226,609		2,927	519,366,332	94
740,215			49,851,965	95
1,509,880		2,927	794,131,487	96
			468,499,422	97
			7,576,095	98
1,509,880		2,927	1,270,207,004	99
414,201,553	158,692	6,502,259	69,067,026,384	100
				101
	351,358		345,946	102
				103
414,201,553	-192,666	6,502,259	69,066,680,438	104

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 95 Column: c

For 2020, PG&E refined its methodology for displaying operative CWIP balances by allocating the balances to the respective functional groups to which they belong according to the nature of the costs compared to 2019 where the entire balance was recorded to FERC account 398. As such, included in the 12/31/20 FERC account 398 plant balance is a reversal of the prior year's operative CWIP balance in the additions column. Operative CWIP is defined as capital orders for projects that are less than 30 days of construction with amounts that remain in CWIP due to capital order settlement issues. The balances for these capital orders should be classified as plant.

Schedule Page: 204 Line No.: 102 Column: g

Plant Purchased or Plant Sold is a holding account for pending transactions related to asset purchases/sales and will be cleared once pending transactions have closed.

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

Netnegative additions are attributed to work orders being reclassified to detailed plant accounts.

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

Electric Plant in Service does not include ASC 842 Operating Leases.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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	None			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	None			
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			0

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	74025800 ELKHORN: INSTALL ENERGY STORAGE SYSTEM	100,617,327
2	74001039 SAN FRAN Y (LARKIN): REPLACE 12KV SWGR	85,421,426
3	35212401 FRRB - MONTICELLO 1101 CB	64,194,245
4	74007941 CALTRAIN INTERCONNECTIONS SUB SITE 3	34,797,713
5	74001391 60-SOUTH OF PALERMO REINFORCEMENT (PH-1)	34,662,154
6	74000343 CALTRAIN INTERCONNECTIONS SUB SITE 1	33,509,688
7	74001943 WHEELER RIDGE VOLTAGE SUPPORT (SUB)	30,225,384
8	74003484 WILSON: INSTALL STATCOM	27,487,911
9	74001098 TABLE MOUNTAIN: REPLACE 500 KV BK 1	25,315,384
10	74001432 COTTNWD-RED BLUFF - RECONDUCTOR	20,219,496
11	74015502 74015502_IGNACIO - MARE ISLAND TWR REPL	19,970,629
12	74000924 ESTRELLA_CPUC LIC/PER	19,425,205
13	74001780 RIO OSO: INSTALL 230KV BAAH/GIS	18,815,857
14	74004037 TESLA: REPLACE 500 KV SERIES SC BK 2	18,111,168
15	74003069 LOS ESTEROS SHUNT REACTOR PROJECT	16,577,412
16	68053001 COM: Integrated Video Mgt System Upgrade	16,047,325
17	74001782 RIO OSO: INSTALL 115 KV BAAH/GIS	15,266,782
18	74005121 EVERGREEN SUB: 115KV BUS UPGRADE	14,618,602
19	74000925 MIDWAY ANDREW_CPUC LIC/PER	14,101,929
20	74011380 74011380_GREATER BAY ER STORAGE FAC SF	13,943,439
21	74000939 WRJ NONCOMPETITIVE_CPUC LIC/PER	13,520,728
22	74010750 MONTA VISTA: INSTALL 230KV MPAC	13,048,437
23	74002206 GLENN: REPLACE BK 1	12,555,964
24	74001713 HUNTERS POINT: 115KV GIS BAAH	12,164,572
25	31503650 RAVENSWD-SAN MATEO #1 25000FT BW	12,144,242
26	74000901 MARTIN BUS EXTENSION_CPUC LIC/PER	12,104,730
27	74008620 Fordyce Dam Leakage Reduction	11,992,746
28	68017320 COM: Replacement Oily Water Separator Sy	11,523,507
29	74000933 230 KV TLINE LOCKEFORD - NEW INDUSTRIAL	11,414,424
30	74016300 NETWORK SCADA Y-1	10,860,745
31	74001366 CORCORAN SMYRNA 115KV NERC ALERT PROJECT	10,827,908
32	74005663 KERN PP: CONVERT 115KV BUS TO BAAH	10,698,100
33	74001785 RIO OSO: INSTALL 230 KV MPAC	10,695,553
34	74005020 MIDWAY: UPGRADE 230 KV BUS SECTION D	10,391,138
35	74000714 (DA-CE) COLGATE-CHALLENGE RELIABILITY	10,060,669
36	74001856 EL CERRITO G: 115KV BUS UPGRADE PHASE 2	9,883,217
37	74004825 HICKS: IMPROVE 230 KV BUS RELIABILITY	9,702,591
38	74001786 RIO OSO: INSTALL 115 KV MPAC	9,208,435
39	74001200 EXCHEQUER SUB TO BEAR VALLEY SUB	9,015,986
40	74001454 Pit 1 LLO Gate Rplc & Radial Gate Seals	8,612,793
41	13003982 DS-C Relic- Cond studies for all RA	8,517,659
42	74008281 Bucks Cr PH Repl U2 Turb Brg / Shaft	8,514,412
43	TOTAL	1,929,075,179

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	74003264 Caribou 1 U1 Repl Runners, Bearing&Shaft	8,450,835
2	74003450 CASCADE: INSTALL MPAC	8,156,679
3	74003661 Bucks Creek U1 Generator Stator Rewind	7,939,220
4	74001485 EP BAILEY RD CONTRA COSTA CNTY R20A	7,920,785
5	74001781 RIO OSO: INSTALL BK 1 AND BK 2	7,592,792
6	74002486 KERN PP: INSTALL 115KV MPAC BLDGS	7,546,146
7	74002846 SANTA TERESA: INSTALL NEW SUBSTATION	7,471,156
8	7089887 Kerckhoff Rel Studies	7,427,806
9	74015260 CASCADE: INSTALL BK 2 PHASE 1	7,357,180
10	74009587 Pit 1 U1 Rewind Generator	7,164,768
11	74026141 DUNLAP SUB: EM REP BK 1	7,133,021
12	74010764 MESA-SANTA MARIA 115KV NERC	6,686,794
13	74016420 STANISLAUS 1701-FOREST MEADOWS UG REPL	6,648,062
14	74008746 MALIN-ROUND MOUNTAIN #2-500 KV INS REPL	6,508,505
15	74004826 67-HICKS: INSTALL 230KV MPAC (CONSTR 201	6,486,890
16	74000900 Bucks Creek U2 Generator Rewind	6,374,550
17	74008748 LOS BANOS-MIDWAY #2 500KV LINE INS REPL	6,182,264
18	74000709 (DA-TRC) HUMBOLDT BAY RECOND. PROJ. 2021	5,995,858
19	74016583 Electra U2 Generator Rewind	5,962,234
20	74021760 MIDWAY SUB: INSTALL 230kv MPAC	5,788,110
21	74001959 TABLE MOUNTAIN: REP 500KV CAP BK 3	5,714,002
22	74004807 SOLEDAD: INSTALL D-BANK 7	5,697,321
23	74000731 EAST SHORE-OAKLAND J 115KV RECONDUCT(TL)	5,617,811
24	74022546 VGCC_IMPLEMENT EMS RTSRM	5,537,643
25	68045781 PLO-COM: REPL PAC 0-1 thru 0-7	5,460,103
26	7089447 Potter Valley Rel Studies	5,450,165
27	74010757 TESLA-METCALF 500 KV INSULATOR REPLACE	5,177,623
28	74001175 MOSHER-LOCKFORD 60KV RECOND.	4,775,721
29	74004890 PEASE - REPL BANK 2	4,736,021
30	35031512 MISSION X 1127 NEW FEEDER	4,666,395
31	74001173 LODI: REPLACE CB 12 22 32	4,642,662
32	74002227 NC_REPLACE BELLEVUE BANK 1	4,641,317
33	74021027 METCALF-GREEN VALLEY 115KV: LINE RECONDU	4,640,988
34	74018123 SF H (MARTIN)-REPL SHUNT REACTOR HZ2	4,481,249
35	74023920 LIVERMORE: EM REP BK 1	4,434,420
36	74026644 DRUM PH 1: REPLACE SW 363 STRUCTURE-WSIP	4,403,885
37	74008802 INST ROSSMOOR 1109 FDR_MORAGA BK5 EMERG	4,379,204
38	74014380 4TH ST EUREKA R20A	4,318,019
39	74024705 C1106 NETWORK PRIMARY CABLE REPLAC-OAKLA	4,313,722
40	7093365 CWSP - PIH Non Generation	4,236,411
41	74000915 KERN 230KV AREA REIN MIDWAY-KERN 3 & 4 (4,201,955
42	74008009 WILSON-LEGRAND 115KV LINE RECON TL - DO	4,135,473
43	TOTAL	1,929,075,179

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	31066255 R20A - DIAMOND SPRINGS 1A-EL DORADO CTY	4,042,191
2	74015486 ESTRELLA CPUC DATA REQUEST #3	4,026,111
3	74021024 MORGAN HILL SUB: 115KV BAAH CONVERSION	3,981,216
4	74001766 RAVENSWOOD-COOLEY LANDING 115 KV (TL)	3,856,424
5	74001688 NC_(DA-ABB) MAPLE CREEK SUB:REACTIVE SUP	3,855,076
6	35171705 BR-03-12-W (E) PENTZ RD SRTS PARB	3,796,108
7	74001732 VIERRA 115 KV REINFORCEMENT (T-LINE)	3,791,024
8	74000622 BELLOTA - WARNERVILLE RECONDUCTOR	3,779,094
9	74000825 LEMOORE NAS 70 KV SCADA SW#55,65	3,777,687
10	74021440 TSRP NS - IT OTHER SITES	3,767,916
11	74026020 BUCKS CREEK PH RECONNECTION SUBSTATION N	3,708,075
12	74007783 Caribou 1 U2 Repl Runners, Bearing&Shaft	3,676,880
13	74017491 DOLAN SUB, INSTALL NEW BANK	3,668,746
14	35118517 BR-07-05-W (E) FLICKER LN, PARB	3,648,299
15	74026304 TULARE LAKE - REPLACE BANK 1	3,633,249
16	68019302 PLO-U2:Cond. Polisher Cmptr Upgrade	3,605,043
17	74001920 CASCADE: REPLACE 60 KV CB 42 52 62 72	3,556,022
18	31209025 INSIGHT REALTY UG RELOCATION	3,545,560
19	74002214 HOPLAND: REPLACE BK 2	3,537,436
20	74001334 TEMPLOR-SAN LUIS OBISPO 115KV NERC	3,534,924
21	74001802 PIT PH 1: REPLACE 230 KV BK 1	3,382,723
22	13008740 Battle Crk - Phase 2 License Amendment	3,377,287
23	74007648 MONTA VISTA: UPGRADE 230 KV BUS PHASE 2	3,362,992
24	74000345 CHSR INTERCONNECTIONS SUB SITES 4-7	3,361,809
25	74001047 KERN 230KV AREA REIN MIDWAY-KERN 1 & 2	3,318,266
26	74019961 FAMOSO: EM REPL CB 132 & 152	3,291,867
27	74000548 OAKLAND D: REPLACE 115 KV CB 112 132 152	3,290,566
28	74030540 VACA DIXON: REPLACE BANK 2	3,275,734
29	7049829 DC Relic Begin Prep of NOI and PAD	3,253,857
30	68021225 PLO- U2: Replace AFW Chem Inj Pmp	3,247,588
31	31381600 ETTM CONCORD MCC	3,225,328
32	74015784 HIGHWAY 1107 NEW FEEDER	3,221,070
33	74010257 Scott Dam Replace Radial Gate Hoist	3,177,460
34	74015248 TSRP NBS IT NEW MPLS	3,176,486
35	74018545 HERDLYN 60KV RELAY PROJECT	3,152,887
36	74000341 CHSR INTERCONNECTIONS SUB SITES 8-13	3,129,335
37	74035922 DRUM-RIO OSO SOUTH 115KV EMERG REINFORCE	3,083,430
38	74016341 TSRP NBS IT OTHER SITES	3,039,103
39	13011921 NFSL Additional Design Imp	3,009,595
40	74000936 WRJ COMPETITIVE_CPUC LIC/PER	3,004,630
41	74003261 Caribou 1 U1 Rewind	3,002,420
42	35058273 CWSP- EL DORADO 2101 OCB ZONE PHASE 1	2,968,017
43	TOTAL	1,929,075,179

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	74016862 AQUAMARINE WESTSIDE GATES SUB RNU	2,953,958
2	7053945 DC Relic - Prepare Study Plans	2,939,134
3	74022160 PLACER: EM REPL BK3 WOOD POLE STRUCTURES	2,936,386
4	74000842 SEMITROPIC: 115KV LINE RECOND	2,904,016
5	74001792 RED BLUFF-COLEMAN REINFORCEMENT	2,850,449
6	74017381 METCALF: INSTALL 230 KV MPAC	2,810,825
7	74018846 1320WD STRAUSS WIND T-LINE DA	2,804,425
8	74017519 VACA DIXON: INSTALL 230 KV SMART WIRES	2,778,451
9	35109547 CWSP - EL DORADO 2101 - 19752 -PHASE 2.4	2,759,322
10	74015040 REINFORCE MORAGA 1102-SOBRANTE 1101	2,752,307
11	7087874 Permit Holdover Project - Shasta-Trinity	2,738,107
12	74010660 Balch 2 - U2 Replace Cooling Water	2,732,820
13	31326189 CONTROL CENTER SYSTEM UPGRADE	2,703,498
14	74002410 Pit 5 TGB Install Inline Oil Filtration	2,697,174
15	7043247 RCC Lic Imp Cold Water Feasibility Study	2,687,809
16	74008384 Battle Cr Salmon/Steelhead Phase 2	2,648,324
17	74009061 WESTPARK: INSTALL MPAC BUILDING	2,626,334
18	68058200 PLO: COM: MW Links 12A & 13A Mod	2,589,829
19	74001057 Halsey PH Replace Runner and Seal Rings	2,554,825
20	7089450 Phoenix Rel Studies	2,552,783
21	74009960 SOBRANTE: UPGRADE PHYSICAL SECURITY	2,540,443
22	35180296 BR-06-01-O (E) DELIA WAY PARB	2,533,235
23	74005355 RIO OSO SUB: SVC	2,483,756
24	31381602 ETTM FRIENDLY VILLAGE	2,455,166
25	13002402 DS-C Relic- Conduct Pre-App Proj Man	2,446,314
26	74000707 60 KINGSBURG-LEMOORE 70KV RECOND. PH1	2,433,919
27	7093170 Wildfire Wire Down detection	2,428,654
28	74007020 SANTA TERESA SUB TLINE WORK	2,411,321
29	74032360 FMC-SAN JOSE TPS 115KV CALTRAIN INTERCON	2,386,937
30	74029411 GATES BK 12 CONDUIT/TRENCH FAILURE REPL	2,385,149
31	31306492 EMS Replacement Hardware	2,368,364
32	74006884 MORRO BAY SUB: UPGRADE 230KV BUS	2,345,835
33	74011242 IGNACIO-MARE ISL 115KV (IGN SUB/HWY SUB)	2,325,911
34	74001735 POTRERO-MISSION #1 (A-X 1) SEISMIC RETRO	2,299,903
35	74012040 NICOLAUS-WILKINS SLOUGH 60KV LINE POLE	2,281,481
36	74031330 COLUSA: EMERGENCY REPLACE BANK 2	2,276,678
37	74002827 OAKLAND L: INSTALL SCADA	2,273,766
38	35029720 DOWNTOWN STOCKTON PH 1 R20A	2,257,176
39	35064793 LP RECONDUCTOR, CABRILLO 1104 S006CC102	2,235,165
40	74003803 Q954 FIFTH STANDARD SOLAR (NU) GATES	2,234,807
41	74007157 KERN PP 115KV TLINE	2,234,626
42	74002161 NC_PENNGROVE 115/12KV BK 1	2,204,615
43	TOTAL	1,929,075,179

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	7097928 HBGS Engine 5 Repair	2,197,987
2	74013481 KERN 230KV BAAH PHASE 3	2,185,027
3	74002248 NV_TESLA SUB: REPLACE MOBILE TXFR T-22-2	2,181,037
4	74013528 R20A - FULTON RD SANTA ROSA	2,180,737
5	74036853 MORAGA-OAKLAND X 115KV #1&2 RECOND	2,146,478
6	74000937 MERCY SPRINGS - CANAL SS T-LINE RECONDUCT	2,128,141
7	74018722 Tgr Crk Cnl Install Flume Lnr 2020/2021	2,099,482
8	35112425 CWSP - EL DORADO 2101 - OCBZONE - PH 1.2	2,098,210
9	74008740 GATES-MIDWAY 500KV LINE INS REPL	2,088,343
10	74025701 X-1123 NETWORK PRIMARY REPLACEMENT	2,084,010
11	13009580 DeSabra Replace Governor	2,072,742
12	74010323 Poe PH Deck/Roof Resurface	2,070,331
13	74006821 BIRDS LANDING SS-CONTRA COSTA PP 230KV.	2,053,368
14	74001854 EL CERRITO G: REPL BANK 1	2,041,213
15	74001993 JARVIS: REPLACE BK2 WITH 45MVA BANK	2,040,363
16	74016585 Caribou 1 U2 Generator Rewind	2,038,914
17	7089448 Phoenix Rel Project Management	2,021,854
18	35025785 2019 WEBER INSTALL NEW FEEDER	2,014,175
19	74001733 POTRERO-LARKIN #2 (A-Y2) SEISMIC RETROFI	2,007,180
20	35118702 BR-11-03-W (E) GREGS WAY, PARB	1,999,510
21	7094827 HBGS Warehouse and Workshop	1,991,994
22	74010363 KERN PP-LIVE OAK 115KV LINE RECONDUCTOR	1,989,965
23	74001734 MARTIN-LARKIN #1 115 KV CABLE (H-Y 1)	1,986,114
24	74003102 Balch 2 U3 Repl Cooling Wtr Piping	1,984,558
25	35170663 BUCOCAMPM CRESTA PH - HWY 70 OROVILLE	1,964,696
26	31375431 ETTM VALLEJO MOBILE HOME PARK	1,956,677
27	7089886 Kerckhoff Rel PAD and NOI	1,955,657
28	74016340 TSRP NBS IT T-LINE SWITCHES	1,943,006
29	74036404 PIERCY: EM REPLACE BK3	1,933,178
30	74021700 MIDWAY SUB: T-LINE WORK 230KV	1,929,701
31	74007740 CASTRO VALLEY: REP SWGR REROUTE FEEDR	1,928,470
32	74021361 WOODLAND: EM INSTA CONTROL BUILDING	1,917,418
33	74001686 NC_MAPLE CREEK PROJ-BUS RECONFIGURATION	1,912,212
34	68061840 PLO:COM Security Def Strategy Upgde	1,892,865
35	74009953 DELEVAN SUB: PHYSICAL SECURITY UPGRADE	1,890,886
36	74000580 DRUM-RIO OSO #1-115KV IMPRV (STEEL)	1,862,934
37	74001397 (DA-TRC)ESSEX JCT ORICK 60KV RELIABILITY	1,854,921
38	35116442 CWSP-MIWUK 1702-LR 38218-PH 1.3	1,852,690
39	74020313 YOSEMITE PARK: SPCC FENCING/BARRIER	1,850,341
40	35094031 MISSION SF X-1128 INSTALL NEW FEEDER	1,849,084
41	74002366 PITTSBURG: INSTALL 230/115KV TRANSFORMER	1,838,578
42	31242522 ECEIR2Z EP BARRY ROAD SUTTER COUNTY R20A	1,822,082
43	TOTAL	1,929,075,179

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	74022421 VALLEY SPRINGS: INSTALL 60/12KV BANK	1,818,459
2	30754659 R1 WEST LELAND RD PITTSBURG R20A	1,816,219
3	35117443 CWSP-BRUNSWICK 1103 LR50070 ZONE-PH 3.6	1,813,139
4	74011243 IGNACIO-MARE ISL 115KV (HWY SUB/COR SUB)	1,812,742
5	74003501 SUMMIT: REPL 60 KV SW 37 & SW OPERATOR	1,787,048
6	74023700 VINA: REPLACE BANK 1	1,784,540
7	74001486 GRIZZLY PEAK BLVD BERKELEY R20A	1,783,252
8	74002973 RADUM PROTECTION UPGRADE	1,780,502
9	68040201 PLO-COM:Wedge Barrier System- GATE 20	1,775,620
10	74016584 Tiger Creek U2 Generator Rewind	1,764,180
11	7089885 Kerckhoff Rel Project Management	1,752,537
12	74021321 STANISLAUS - MANTECA #1 115KV RPL COND (1,746,222
13	74015908 EMBARCADERO-POTRERO: UPGD SF RAS B AT VG	1,712,771
14	74025440 Bucks Cr Repl GSU XFMR 251T Relay NERC	1,710,552
15	74024307 EL CERRITO G: EM_REPL TRANSF TRIP RELAY	1,707,706
16	74003970 MONTEREY: INSTALL 3-D-BANKS & 60KV T BRK	1,703,347
17	74020500 BRIGHTON: REPLACE OB INSULATORS	1,701,632
18	35082249 BUCO ETTM EDGEWOOD/SAWMILL ESTATES	1,700,521
19	74001855 EL CERRITO G: 115KV BUS UPGRADE T-LINE	1,698,745
20	7096952 EMS Video Wall Windows 10 Upgrade	1,696,206
21	74007644 RAVENSWOOD-SAN MATEO 115KV PH2 NERC PROJ	1,695,298
22	7094525 Appian Phase II	1,691,076
23	74004581 +R5 MESA 1104 FEEDER - PHASE 2	1,685,246
24	74016063 EMBARCADERO-POTRERO SF RAS A AT SFGO	1,664,798
25	74011680 OCGC REARRANGEMENT OF ED FACILI	1,653,922
26	74021261 OLEUM-NORTH TOWER-CHRISTIE	1,649,982
27	74018540 CASCADE - TLINE SUPPORT	1,642,885
28	74002153 RAVENSWOOD:REPL 115KV RD-PALO A 1,2 REL	1,635,181
29	68047884 PLO-U2:Repl Aux Transfmr 2-1 Radiators	1,626,053
30	74024583 STOCKDALE: REPL D-SCADA 10 IPAC	1,623,023
31	74002782 BAY MEADOWS: REPLACE D-RTU	1,587,899
32	35111486 BR-04-03-W (E) EDWARDS & RIPLEY PARB	1,579,202
33	7097651 GGS Op Flex Balance/Advantage	1,574,337
34	35130701 BR-04-01-F (E) SUNSET DR PARB	1,559,520
35	35053171 EXTEND EDENVALE 2105 FEEDER	1,558,365
36	74003620 Cresta PH Repl Tailrace Gates	1,543,382
37	74015503 AGED TWR REP PH1	1,542,256
38	7096406 DTS-FAST Pilot 21	1,541,521
39	35082251 BUCO ETTM SHERWOOD FOREST MHP	1,536,714
40	74008017 BERKELEY T: CONV 12KV 1 OF 3 OAKLAND	1,525,827
41	7096573 Construction	1,501,384
42	74017026 Helms - U2 Repl TSV	1,498,306
43	TOTAL	1,929,075,179

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	68045340 PLO: COM:ACCESS RD COMMUNICATIONS	1,495,065
2	74000342 CALTRAIN INTERCONNECTIONS T-LINE SITE 1	1,487,918
3	74024690 GOLD HILL: REPL CB 242,712	1,478,579
4	35061212 CWSP-BRUNSWICK 1103 LR50070 ZONE-PH 2.1	1,478,449
5	13002403 DS-C Relic- Conduct Studies	1,465,011
6	74003282 HUNTERS POINT: REPL 12KV BUS WITH SWGR	1,451,030
7	74014140 MONTA VISTA: UPGD SLAC RE RLY	1,437,290
8	35116391 CWSP - MIWUK 1702 - OCB - PH 1.2	1,432,949
9	74002409 Kerckhoff Dam Instl Remote Op Fish Rel	1,415,454
10	74001571 EMBARCADERO SUB: REPL BANK 1	1,414,158
11	74007447 PANOCHÉ-ORO LOMA 115 KV LINE RECONDUCTOR	1,403,044
12	7049828 DC Relic Project Management	1,394,967
13	74014687 PIT PH#1 - 230 KV - REPL BANK 2	1,392,931
14	31274349 CAL WATER 1102 BACKTIE	1,392,770
15	74034266 Haas U2 Rotor Pole Refurb	1,385,673
16	35105653 BR-14-01-W (E) SALIDA WAY, PARB	1,369,775
17	74002152 PA SW STA: REPL PA-RAVENSWOOD RELAY	1,360,589
18	74023524 TSRP NS - IT NEW MPLS	1,355,233
19	13006781 DeSabra-Centerville Proj Mgmt Post LA	1,353,139
20	35116801 CWSP-MIWUK 1702-LR 6018-PHASE 1.3	1,352,066
21	74000686 NEW HOPE: INSTALL D-SCADA CB 1101, 1102	1,349,799
22	74003600 Helms Replace Load Center 1, 2, 7 & 8	1,348,948
23	35029548 MONTEREY SUBSTATION LINE WORK	1,345,968
24	74026862 STOCKDALE 230KV LINE TAPS #1 AND #2 REMO	1,339,595
25	74001722 VIERRA: LOOP 115 KV LINE BAAH	1,311,984
26	35116800 CWSP-MIWUK 1702-LR 6018-PHASE 1.2	1,310,360
27	74003761 Rock Cr PH Repl Tailrace Gates	1,306,282
28	7096570 Lasers, Technology and Arc flash	1,304,405
29	74000665 BRIGHTON-GRAND ISLAND #1 & #2 115KV NERC	1,298,209
30	7097305 HBGS UNIC Upgrade	1,284,223
31	74005347 WOODLAND: INST RIO OSO 115KV REMOTE END	1,278,005
32	74011312 HUMBOLDT BAY PP GENERATOR RELAYS	1,274,169
33	74007987 PRC 002-2 PITTSBURG 230KV FR	1,273,563
34	74030684 TSRP_NBS_SUB_VACA DIXON	1,268,202
35	74000902 LOOP HZ1 INTO EGBERT SW. STATION	1,268,085
36	74009901 Rock Cr PH U1 & U2 Repl WG Seals	1,264,324
37	74024720 GREGG: EM REP 230 KV BUS DIFF RLYS	1,257,350
38	74009027 POTRERO: REPLACE SVC CONTROLLER	1,245,600
39	35129975 BR-03-11-F (E) WHITAKER RD PARB	1,239,596
40	74010864 WARNER ST CHICO R20	1,232,365
41	74024201 Hat Creek 2 Repl Transformer Bk-1-ABC	1,229,121
42	74002140 CUYAMA: INSTALL T-SCADA	1,229,008
43	TOTAL	1,929,075,179

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	74001504 WESTPARK: REPLACE CB 1101 - 1104 12KV	1,222,509
2	74007942 CALTRAIN INTERCONNECTIONS T-LINE SITE 3	1,209,417
3	74032400 OAKLAND C REPALCE 115_12KV BANK 2	1,205,366
4	74016040 Helms - U1 Repl TSV	1,197,308
5	74013925 R20A - DIAMOND SPRINGS 1C-EL DORADO CTY	1,191,261
6	74019702 DEL MONTE - FORT ORD#1	1,190,412
7	74001363 IGNACIO-MARE ISLD #1 115KV NERC STEEL	1,188,390
8	35105703 INSTALL DISTR LINE FROM NEW LARKIN SWTGR	1,182,665
9	74021035 RAVENSWOOD SUB DE STRUCTURE REPLACEMENT	1,177,168
10	74015250 TSRP NBS IT VSAT	1,176,483
11	31403458 EMS FEP SITES POWER UPGRADES	1,170,141
12	74008861 ROSSMOOR: INST 1109 FDR AND REINF TIES	1,169,477
13	74002400 Pit 4 Replace PSV Valve Controls	1,166,708
14	74007989 PRC 002-2 CONTRA COSTA PP 230KV FR	1,166,499
15	74011503 LODI SUB:60KV T-LINE REARRG -ENGINEERING	1,165,973
16	74009206 TABLE MTN:REPL 500KV TM-ROUND MTN #2 REL	1,162,069
17	74026612 Electra U2 Generator Relays Rpl	1,157,571
18	74001435 (DA-B&M) ELECTRA TO WEST PT SCADA SWT.	1,152,199
19	74020328 HAMILTON BRANCH: REPL CB 12 RELAYS	1,149,431
20	35114040 CWSP - PINE GROVE 1102 - LR1222 - PH 1.2	1,146,018
21	31453483 VGCC_IMPLEMENT EMS-TOTL INTERFACE	1,145,590
22	74007643 RAVENSWOOD-BAIR #2 115KV PH2 NERC PROJEC	1,139,013
23	74016661 EDES: 115KV RECONDUCT FIBER INTERCONNECT	1,136,333
24	74001542 OAKLAND K (CLAREMONT): REPLACE 12KV SW	1,134,880
25	74017028 Helms - U3 Repl TSV	1,133,691
26	74000904 REROUTE JEFFERSON_MARTIN 230KV LINE	1,127,782
27	74020942 VACA DIXON: REPLACE BANK #5	1,120,084
28	7093106 Phoenix Rel License Application	1,117,285
29	31511908 T3 BURNS-LONE STAR #1 - 60 KV FIRE	1,115,747
30	74001332 KINGSBURG CORCORAN 1 AND 2 115KV NERC	1,108,587
31	74012600 STATION M REBUILD- DIST WORK	1,097,993
32	74010185 Caribou 1 U1 Upgrade Gov Controls	1,095,726
33	74002170 OLEMA: INSTALL SCADA SW27 & 29	1,094,503
34	7096574 Monitoring Center and Networking	1,091,967
35	74024207 Pit 5 U4 Rplc WGs, FPs and Seals	1,091,145
36	74015501 74015501_IGNACIO - ALTO - SAUSALITO 60KV	1,077,075
37	30988481 AD GEP T 8102 MOLLER RANCH@TASSAJAR	1,074,000
38	74002120 Pit 4 Replace Generator Air Breakers	1,071,706
39	74029542 Tiger Crk Reg Spillway Upgrade SAIP (C)	1,069,974
40	35115054 CWSP - MIWUK 1701 - OCB - PH 2.2	1,059,622
41	74000671 SALT SPRINGS-TIGER CREEK NERC PROJECT	1,059,253
42	74015244 TSRP NBS IT CROSS CONNECTS	1,056,862
43	TOTAL	1,929,075,179

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	74032102 COLUSA: JIT REPLACE BANK 1	1,056,827
2	74032721 FAIRWAY: REPLACE BANK 2	1,023,159
3	74001088 BAKERSFIELD-KERN 230KV LINE 1&2 RECOND	1,015,163
4	74020261 LAMMERS-KASSON 115KV TWR REPL	1,005,191
5	74010227 Tiger Ck Forebay Replace Trash Rakes	1,003,240
6	See footnote for detail.	306,344,294
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43	TOTAL	1,929,075,179

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 216.8 Line No.: 6 Column: b

This is the aggregate total of projects with less than \$1,000,000 in actual costs in Construction Work in Progress, including credits representing preliminary billings.

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	28,298,971,651	28,298,971,651		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	2,461,733,443	2,461,733,443		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Reverse Common Allocation	-163,109,222	-163,109,222		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	2,298,624,221	2,298,624,221		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	410,935,805	410,935,805		
13	Cost of Removal	404,547,286	404,547,286		
14	Salvage (Credit)	7,650,337	7,650,337		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	807,832,754	807,832,754		
16	Other Debit or Cr. Items (Describe, details in footnote):	84,103,975	84,103,975		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	29,873,867,093	29,873,867,093		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	359,069,008	359,069,008		
21	Nuclear Production	7,261,817,389	7,261,817,389		
22	Hydraulic Production-Conventional	1,527,608,258	1,527,608,258		
23	Hydraulic Production-Pumped Storage	799,016,289	799,016,289		
24	Other Production	428,917,631	428,917,631		
25	Transmission	3,611,126,808	3,611,126,808		
26	Distribution	15,216,731,320	15,216,731,320		
27	Regional Transmission and Market Operation				
28	General	669,580,390	669,580,390		
29	TOTAL (Enter Total of lines 20 thru 28)	29,873,867,093	29,873,867,093		

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

This reconciles with the cost of plant retired shown on pages 204-207, column d, as follows:

Book cost of depreciable plant retired	410,935,805
Book Cost of Amortizable Plant Retire	3,265,748
Book cost of plant retired, pages 204-209, column (d)	<u>414,201,553</u>
Diff	0

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

Other Debit or Cr. Items (Describe):

FAS 143 Assets Depreciation (Nuclear & Fossil)	74,035,360
Decommissioning reclass to Regulatory Liability (Nuclear, Fossil, Hydro, Solar)	(34,991,585)
FIN 47 Asset Depreciation (EDP, EHP, ETP, EGP)	33,364,309
Capital Lease Obligations	-
Mirant Adjustment	2,169,529
Gain/Loss	10,106,442
Misc Adjustment	<u>(580,080)</u>
	<u>84,103,975</u>

Schedule Page: 219 Line No.: 25 Column: c

FAS 109 Gross-up on Diablo Canyon Power Plant Utility Asset I is included in General Plant.

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	Eureka Energy Company			
2	Common Stock	1978		1,000
3	Additional Paid in Capital			3,727,170
4	Undistributed Earnings			-102,438
5				
6	SUBTOTAL			3,625,732
7				
8	Natural Gas Corporation of California			
9	Common Stock	1954		100,000
10	Additional Paid in Capital			3,037,432
11	Undistributed Earnings			-3,137,432
12				
13	SUBTOTAL			
14				
15	Pacific Energy Fuels Company			
16	Common Stock	1989		10,000
17	Additional Paid in Capital			4,890,952
18	Undistributed Earnings			-5,604,573
19				
20	SUBTOTAL			-703,621
21				
22	Standard Pacific Gas Line Incorporated			
23	Common Stock	1930-32		1,200
24	Additional Paid in Capital	1954		45,890,210
25	Undistributed Earnings			-29,337,919
26	Advances: Note	05/09/1988	DEMAND	1,127,868
27	Note	09/06/1988	DEMAND	2,580,000
28	Note	12/30/1988	DEMAND	8,712,308
29	Note	08/22/1989	DEMAND	2,880,000
30	Note	10/09/1990	DEMAND	4,200,000
31	Note	02/25/1992	DEMAND	3,300,000
32	Note	12/01/1993	DEMAND	1,518,000
33				
34	SUBTOTAL			40,871,667
35				
36	Midway Power LLC			
37	Additional Paid in Capital	2008		26,112,410
38	Undistributed Earnings			-21,689,847
39				
40	SUBTOTAL			4,422,563
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	48,216,341

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	PG&E AR Facility LLC			
2	Additional Paid in Capital	2020		
3	Undistributed Earnings			
4				
5	SUBTOTAL			
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41				
42	Total Cost of Account 123.1 \$	0	TOTAL	48,216,341

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 from investments, including such revenues from 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
		1,000		2
		4,115,136		3
-226,509		-328,947		4
				5
-226,509		3,787,189		6
				7
				8
		100,000		9
		3,037,432		10
		-3,137,432		11
				12
				13
				14
				15
		10,000		16
		4,890,952		17
275,326		-5,821,189		18
				19
275,326		-920,237		20
				21
				22
		1,200		23
		54,238,521		24
-37,026		-30,642,022		25
		1,127,868		26
		2,580,000		27
		8,712,308		28
		2,880,000		29
		4,200,000		30
		3,300,000		31
		1,518,000		32
				33
-37,026		47,915,875		34
				35
				36
		26,145,744		37
-17,220		-21,707,067		38
				39
-17,220		4,438,677		40
				41
29,086,864		134,313,797		42

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from 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
		50,000,000		2
29,092,293		29,092,293		3
				4
29,092,293		79,092,293		5
				6
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29,086,864		134,313,797		42

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)	961,981	1,378,183	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)	460,127,152	460,961,357	ALL
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,061,195	11,965,536	ALL
8	Transmission Plant (Estimated)	26,047,165	18,207,207	ALL
9	Distribution Plant (Estimated)	40,380,237	42,144,743	ALL
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			GAS
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	549,615,749	533,278,843	
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)	550,577,730	534,657,026	

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		2021	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	157,535.00		13,860.00	
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	3.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	157,532.00		13,860.00	
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	199.00		199.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	199.00			
40	Balance-End of Year			199.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		5		
45	Gains		5		
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/transfersors 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.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
13,860.00		13,860.00		360,360.00		559,475.00		1
								2
								3
				13,860.00		13,860.00		4
								5
								6
								7
								8
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								19
						3.00		20
								21
								22
								23
								24
								25
								26
								27
								28
13,860.00		13,860.00		374,220.00		573,332.00		29
								30
								31
								32
								33
								34
								35
199.00		199.00		9,751.00		10,547.00		36
				398.00		398.00		37
								38
				199.00		398.00		39
199.00		199.00		9,950.00		10,547.00		40
								41
								42
								43
						3		8 44
						3		8 45
								46

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 1 Column: m

Total beginning balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately \$408,680,309 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately \$430,000 in alternative fuel vehicle credits.

Schedule Page: 228 Line No.: 29 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line item on page 110. Difference is due to approximately \$511,839,840 in CO2 allowances issued by the California Air Resources Board (CARB) and approximately \$430,000 in alternative fuel vehicle credits.

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

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/transferees 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.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
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								38
								39
								40
								41
								42
								43
								44
								45
								46

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Santa Cruz 115 kV Reinforcement	3,557,222	3,557,222			
22	October 4, 2016 (03-2016 to 12-)					
23						
24	Atlantic-Placer 115kV Transmissit	324,906	324,906			
25	October 2019 (1/1/2020 to 12/31/)					
26						
27	Mesa (Diablo Canyon Voltage Supp)	1,110,344	1,110,344			
28	October 2019 (1/1/2020 to 12/31/)					
29						
30	Gates - Gregg	7,101,333	7,101,333			
31	March 2020 (1/1/2020 to 12/31/20)					
32						
33	Pease - Marysville #2 60 kV Line	3,155,191	3,155,191			
34	November 2020 (1/1/2020 to 12/31)					
35						
36	Jefferson - Stanford #2 60 kV Lil	1,334,116	1,334,116			
37	November 2020 (1/1/2020 to 12/31)					
38						
39	South of San Mateo Capacity Incre	902,589	902,589			
40	November 2020 (1/1/2020 to 12/31)					
41						
42	Bay Meadows 115 kV Reconductoring	708,816	708,816			
43	November 2020 (1/1/2020 to 12/31)					
44						
45	Kerckhoff PH #2 - Oakhurst 115 ke	274,978	274,978			
46	November 2020 (1/1/2020 to 12/31)					
47						
48	Refer to footnote for add. lines	76,371,287	24,576,077			51,795,210
49	TOTAL	94,840,782	43,045,572			51,795,210

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 48 Column: a

During 2020, there were additional lines needed to present the activity for Unrecovered Plant and Regulatory Study Costs which the FERC software would not allow to be added. As such, we have added the totals on the FERC pages and included the breakdown of those amounts below.

(a)	(b)	(c)	(d)	(e)	(f)
West Point - Valley Springs 60 kV Line November 2020 (1/1/2020 to 12/31/2020)	71,099	71,099	-	0	0
Soledad 115/60 kV Transformer Capacity November 2020 (1/1/2020 to 12/31/2020)	46,362	46,362	-	0	0
Napa - Tulucay No. 1 60 kV Line Upgrades November 2020 (1/1/2020 to 12/31/2020)	39,983	39,983	-	0	0
Clear Lake 60 kV System Reinforcement November 2020 (1/1/2020 to 12/31/2020)	35,304	35,304	-	0	0
Taft 115/70 kV Transformer #2 Replacement November 2020 (1/1/2020 to 12/31/2020)	32,372	32,372	-	0	0
Monta Vista - Los Gatos - Evergreen 60 kV Project November 2020 (1/1/2020 to 12/31/2020)	31,157	31,157	-	0	0
Cressey - North Merced 115 kV Line Addition November 2020 (1/1/2020 to 12/31/2020)	27,777	27,777	-	0	0
Tesla - Newark November 2020 (1/1/2020 to 12/31/2020)	288,461	288,461	-	0	0
ALMADEN (LOS GATOS) 60KV SHUNT CAPACITOR November 2020 (1/1/2020 to 12/31/2020)	27,579	27,579	-	0	0
VACA-LAKEVILLE	5,933,926	5,933,926	-	0	0
FERC FORM NO. 1 (ED. 12-87)	Page 450.1				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
PACIFIC GAS AND ELECTRIC COMPANY		04/13/2021	2020/Q4
FOOTNOTE DATA			
November 2020 (1/1/2020 to 12/31/2020)			
Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor November 2020 (1/1/2020 to 12/31/2020)	724,676	724,676	- 0 0
Evergreen - Mabury 60 to 115 kV Conversion November 2020 (1/1/2020 to 12/31/2020)	1,606,258	1,606,258	- 0 0
Rio Oso - Atlantic 230 kV Line Project November 2020 (1/1/2020 to 12/31/2020)	824,979	824,979	- 0 0
Watsonville Voltage Conversion November 2020 (1/1/2020 to 12/31/2020)	2,341,382	2,341,382	- 0 0
Reedley-Dinuba November 2020 (1/1/2020 to 12/31/2020)	436,885	436,885	- 0 0
Reedley-Orosi November 2020 (1/1/2020 to 12/31/2020)	304,604	304,604	- 0 0
DCPP License Renewal Cost January 1, 2018 (01-2018 to 12-2025)	12,302,620	2,050,436	- 0 10,252,184
DCPP Canceled Projects January 1, 2018 (01-2020 to 12-2025)	51,295,864	9,752,837	- 0 41,543,026
Total	94,840,782	43,045,572	0 0 51,795,210

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	(see details in footnotes)	4,072,022	186	(2,891,543)	186
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	(see details in footnotes)	2,177,288	186	(2,276,866)	186
23					
24					
25					
26					
27					
28					
29					
30					
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40					

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

FOOTNOTE DATA

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

	Balance 12/31/2019	Costs Incurred	Reimbursements received	Balance 12/31/2020
	\$	\$	\$	\$
WL -(SIS)Interconnection Merced Irr Dist		(500)		(500)
WG - USE - Cluster Analysis		107,759		107,759
WG Gradient Resources Project SIS		22,884		22,884
WAPA O'Neill Substation - System Impact	4,623	(4,623)		0
WG - BURNS&MCDONNELL-Cluster work	5,518	52,289		57,807
WG - C6 - Cluster 6 Phase 2		24,434		24,434
Ntwrk Eval for Calpine 115kV Geysers Gen	(10,369)			(10,369)
WG - C8 - SM - Quail Creek Solar 1		128		128
WAPA - Cottonwood Olinda line work	106,089			106,089
LBNL Capacity Increase		4,654		4,654
SVP Breaker Replacement	(8,863)			(8,863)
Travis AFB Facility Study	(64,156)			(64,156)
Port of Stockton Load Increase	(21,890)			(21,890)
WAPA SLTP	3,044			3,044
Port of Stockton FAS	(40,364)			(40,364)
CAISO ISP Panoche		(261)		(261)
SFPUC - Potrero Interconnection	5,703			5,703
WG - ISP - Porthos		1,680		1,680
WAPA Lemoore NAS	33,346	32,520		65,866
WG # Cluster 11 Phase 1	141,043			141,043
WG - Quanta Technology DG Study Rule 21	(350)	7,092		6,742
WG - Cluster 11 Phase 2	727,322	32,233	(642,701)	116,855
Cluster 12 Phase 1	551,088	565,077	(951,179)	164,987
Lemoore NAS Facilities Study (Yr 2020)		40,502		40,502
WDT/ System Impact Study		9,781		9,781
LLNL FAS for Site 300		576		576
CP-Martin 115/60 kV Upgrade Project	2,045	83		2,128
WL - Tesla Tracy 230kV Line 1 Reloc-FAS	13,216			13,216
Trans Bay Cable Quick Start Study	5,264			5,264
WDL-FAS-Mission Rock Redevelopment		2,378		2,378
WDL-FAS-2 Rankin			(70,000)	(70,000)
WDL-SIS-6527 Calaveras			(50,000)	(50,000)
WDL-SIS-2 Rankin		4,897	(25,000)	(20,103)
WDL-SIS-49 S. Van Ness		7,352	(25,000)	(17,648)
WDL-SIS-750 Phelps		5,803	(25,000)	(19,197)
WDL-FAS-750 Phelps		5,448	(70,000)	(64,552)
WDL-SIS-603 Jamestown/Candlestick		3,346		3,346
WDL-FAS-603 Jamestown/Candlestick		333	(70,000)	(69,667)
WL - CA HiSpeed Train Interconnect Study	23,850			23,850
Swan Lake Affected Sys. Study	82,245			82,245
WG # ISP-South Belridge Expansion	27,453			27,453
WG - C11 - SM - Project 100		(42)		(42)
WG - C11 - SM - Project 76		144		144
WG - C11 - SM - Project 78		(42)		(42)
WG - C11 - SM - Project 95	35			35
WG # Cluster 10 Phase 2	31,191			31,191
WG - 2019 Reassessment and Downsizing St	391,303		(355,730)	35,573
WG - ISP Ceres Energy Storage	9,324			9,324
WG - ISP Kuiper Energy Storage	51,200	(12)	(51,188)	

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FOOTNOTE DATA

WG – ISP Riviera Solar	7,461		7,461
WG – ISP Camptonville Biopower 1	32,975	4,005	(36,979)
WG – ISP Dallas ES 3	44,187		44,187
WG – ISP Dallas ES 2	46,278		46,278
WG - C12 - SM - Project 01	(40)		(40)
WG - C12 - SM - Project 02	(40)		(40)
WG - C12 - SM - Project 03	(21)		(21)
WG - C12 - SM - Project 04	(20)		(20)
WG - C12 - SM - Project 05	(20)		(20)
WG - C12 - SM - Project 06	(20)		(20)
WG - C12 - SM - Project 07	(20)		(20)
WG - C12 - SM - Project 08	(29)		(29)
WG - C12 - SM - Project 09	(20)		(20)
WG - C12 - SM - Project 10	(20)		(20)
WG - C12 - SM - Project 11	(20)		(20)
WG - C12 - SM - Project 12	(20)		(20)
WG - C12 - SM - Project 13	(20)		(20)
WG - C12 - SM - Project 14	(60)		(60)
WG - C12 - SM - Project 15	(20)		(20)
WG - C12 - SM - Project 16	(23)		(23)
WG - C12 - SM - Project 17	(20)		(20)
WG - C12 - SM - Project 18	(20)		(20)
WG - C12 - SM - Project 19	(20)		(20)
WG - C12 - SM - Project 20	(20)		(20)
WG - C12 - SM - Project 21	(20)		(20)
WG - C12 - SM - Project 22	(20)		(20)
WG - C12 - SM - Project 23	(20)		(20)
WG - C12 - SM - Project 24	(40)		(40)
WG - C12 - SM - Project 25	(20)		(20)
WG - C12 - SM - Project 26	(20)		(20)
WG - C12 - SM - Project 27	(20)		(20)
WG - C12 - SM - Project 28	(20)		(20)
WG - C12 - SM - Project 29	(20)		(20)
WG - C12 - SM - Project 30	(20)		(20)
WG - C12 - SM - Project 31	(20)		(20)
WG - C12 - SM - Project 32	(20)		(20)
WG - C12 - SM - Project 33	(20)		(20)
WG - C12 - SM - Project 34	(20)		(20)
WG - C12 - SM - Project 35	(20)		(20)
WG - C12 - SM - Project 36	897		897
WG - C12 - SM - Project 37	(20)		(20)
WG - C12 - SM - Project 38	(20)		(20)
WG - C12 - SM - Project 39	(20)		(20)
WG - C12 - SM - Project 40	(20)		(20)
WG - C12 - SM - Project 41	(20)		(20)
WG - C12 - SM - Project 42	(20)		(20)
WG - C12 - SM - Project 43	(20)		(20)
WG - C12 - SM - Project 44	(20)		(20)
WG - C12 - SM - Project 45	(20)		(20)
WG - C12 - SM - Project 46	(20)		(20)
WG - C12 - SM - Project 47	(20)		(20)
WG - C12 - SM - Project 48	(20)		(20)
WG - C12 - SM - Project 49	(20)		(20)
WG - C12 - SM - Project 50	(19)	19	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

WG - C12 - SM - Project 51	(20)		(20)
WG - C12 - SM - Project 52	(20)		(20)
WG - C12 - SM - Project 53	(20)		(20)
WG - C12 - SM - Project 54	(20)		(20)
WG - C12 - SM - Project 55	(20)		(20)
WG - C12 - SM - Project 56	(20)		(20)
WG - C12 - SM - Project 57	(20)		(20)
WG - C12 - SM - Project 58	(20)		(20)
WG - C12 - SM - Project 59	(20)		(20)
WG - C12 - SM - Project 60	(20)		(20)
WG - C12 - SM - Project 61	(20)		(20)
WG - C12 - SM - Project 62	(40)		(40)
WG - C12 - SM - Project 63	(20)		(20)
WG - C12 - SM - Project 64	(20)		(20)
WG - C12 - SM - Project 65	(20)		(20)
WG - C12 - SM - Project 66	(20)		(20)
WG - C12 - SM - Project 67	(20)		(20)
WG - C12 - SM - Project 68	(20)		(20)
WG - C12 - SM - Project 69	(20)		(20)
WG - C12 - SM - Project 70	(20)		(20)
WG - C12 - SM - Project 71	(20)		(20)
WG - C12 - SM - Project 72	(20)		(20)
WG - C12 - SM - Project 73	764		764
WG - C12 - SM - Project 74	(20)		(20)
WG – Repower Diablo Canyon Repower	21,429		21,429
WG – Austin ES ISP		4,124	4,124
2020 Reassessment		811,885	811,885
WG –Repowering Oakland Unit 2		32,755	32,755
WG - C13 - SM - Project 01		8,919	(8,919)
WG - C13 - SM - Project 02		9,594	(9,594)
WG - C13 - SM - Project 03		8,618	(8,618)
WG - C13 - SM - Project 04		7,263	(7,263)
WG - C13 - SM - Project 05		7,917	(7,917)
WG - C13 - SM - Project 06		6,986	(6,986)
WG - C13 - SM - Project 07		6,850	(6,850)
WG - C13 - SM - Project 08		6,481	(6,481)
WG - C13 - SM - Project 09		6,055	(6,055)
WG - C13 - SM - Project 10		7,740	(7,740)
WG - C13 - SM - Project 11		9,808	(9,808)
WG - C13 - SM - Project 12		6,951	(6,951)
WG - C13 - SM - Project 13		6,379	(6,379)
WG - C13 - SM - Project 14		5,688	(5,688)
WG - C13 - SM - Project 15		8,830	(8,830)
WG - C13 - SM - Project 16		6,919	(6,919)
WG - C13 - SM - Project 17		7,386	(7,386)
WG - C13 - SM - Project 18		8,508	(8,508)
WG - C13 - SM - Project 19		5,891	(5,891)
WG - C13 - SM - Project 20		9,309	(9,309)
WG - C13 - SM - Project 21		5,634	(5,634)
WG - C13 - SM - Project 22		4,256	(4,256)
WG - C13 - SM - Project 23		5,571	(5,571)
WG - C13 - SM - Project 24		(4)	(4)
WG - C13 - SM - Project 25		7,155	(7,155)
WG - C13 - SM - Project 26		6,885	(6,885)

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FOOTNOTE DATA

WG - C13 - SM - Project 27		7,292	(7,292)	
WG - C13 - SM - Project 28		13,662	(13,662)	
WG - C13 - SM - Project 29		8,174	(8,174)	
WG - C13 - SM - Project 30		7,041	(7,041)	
WG - C13 - SM - Project 31		7,187	(7,187)	
WG - C13 - SM - Project 32		6,335	(6,335)	
WG - C13 - SM - Project 33		7,355	(7,355)	
WG - C13 - SM - Project 34		9,891	(9,891)	
WG - C13 - SM - Project 35		7,634	(7,634)	
WG - C13 - SM - Project 36		5,465	(5,465)	
WG - C13 - SM - Project 37		4,665	(4,665)	
WG - C13 - SM - Project 38		5,922	(5,922)	
WG - C13 - SM - Project 39		6,595	(6,595)	
WG - C13 - SM - Project 40		5,102	(5,102)	
WG - C13 - SM - Project 41		6,888	(6,888)	
WG - C13 - SM - Project 42		7,528	(7,528)	
WG - C13 - SM - Project 43		7,152	(7,152)	
WG - C13 - SM - Project 44		7,418	(7,418)	
WG - C13 - SM - Project 45		5,953	(5,953)	
WG - C13 - SM - Project 46		6,852	(6,852)	
WG - C13 - SM - Project 47		6,368	(6,368)	
WG - C13 - SM - Project 48		6,203	(6,203)	
WG - C13 - SM - Project 49		5,631	(5,631)	
WG - C13 - SM - Project 50		7,665	(7,665)	
WG - C13 - SM - Project 52		7,617	(7,617)	
WG - C13 - SM - Project 53		5,664	(5,664)	
WG - C13 - SM - Project 54		4,653	(4,653)	
WG - C13 - SM - Project 55		10,983	(10,983)	
WG - C13 - SM - Project 56		7,744	(7,744)	
WG - C13 - SM - Project 57		5,881	(6,210)	(329)
WG - C13 - SM - Project 58		6,337	(6,337)	
WG - C13 - SM - Project 59		5,886	(5,886)	
WG - C13 - SM - Project 60		5,807	(5,807)	
WG - C13 - SM - Project 61		8,893	(8,893)	
WG - C13 - SM - Project 62		8,171	(8,171)	
WG - C13 - SM - Project 63		13,931	(13,931)	
WG - C13 - SM - Project 64		8,704	(8,704)	
WG - C13 - SM - Project 65		6,925	(6,925)	
WG - C13 - SM - Project 66		4,809	(4,809)	
WG - C13 - SM - Project 67		9,724	(9,724)	
WG - C13 - SM - Project 68		6,737	(6,737)	
WG - C13 - SM - Project 69		7,023	(7,023)	
WG - C13 - SM - Project 70		5,868	(5,868)	
WG - C13 - SM - Project 71		9,817	(9,817)	
WG - C13 - SM - Project 73		7,859	(7,859)	
WG - C13 - SM - Project 74		7,833	(7,833)	
WG - C13 - SM - Project 77		78		78
WG - C12 - Phase II		853,877		853,877
WG - C13 - Phase I		885,241		885,241
WG - Repowering Dollar Wind LLC		32,224		32,224
WG - Oakland ES ISP		1,649		1,649
2021 Reassessment		1,642		1,642
ISP Midland ES		177		177
Total Transmission	2,221,347	4,072,022	(2,891,543)	3,401,827

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

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

	Balance 12/31/2019	Costs Incurred	Reimbursements received	Balance 12/31/2020
	\$	\$	\$	\$
Estrella Substation - Facilities Study	(678)	678		
R21Beldrige Wtr Stor 352165 NEM2 Det Sty	3,239			3,239
WDT - Chevron USA Prod Co ISP	(2,705)	1,407		(1,299)
Shiloh I Wind Project Facilities Study	38,506			38,506
Exchequer RAS - CAISO Post COD	4,296			4,296
MMA - Q1158 Slate - ISO 51731	5,800			5,800
MMA - QF Santa Clara Wind - 51155	4,211			4,211
MMA - Q1096 & QF Altamont Midway - 51156	37,940	392		38,332
MMA - QF Forebay Wind - 51154	1,565			1,565
Q877 California Flats - Roadway PEIE	(480,146)	91,974		(388,172)
Kingsburg Cogen - Facility Study	1,494			1,494
1469-RD BELRIDGE WATER/Detailed	(8,237)	8,237		
WDT - CA-17-0097 SB43 Arco - ISP	1,226			1,226
R21 - Bear Creek - EDMUD - Detailed Stdy	(5,571)	5,571		
WDT-CA-17-0101 SB43 Devils Den-Fst Trk	2,507			2,507
WDT-CA-17-0102 SB43 Gates-ISP	(1,840)	1,840		
CA Department of Corrections #387295/Det	(5,611)	5,611		
WDT CA-17-0100 SB43 Derrick/ISP	1,832			1,832
R21 EBMUD Enos (387729) RESBCT/Detailed	(53,810)	53,810		
WDT SEPV American Canyon/FT	207			207
R21 - Bangor Solar - 1402-RD - Det Stdy	(9,490)	9,490		
WDT-CA-17-0090 SB43 Dulgarian/FT	233			233
R21 - City Count of SF (Enos 390303)/Det	(6,049)	6,049		
1529-RD City of Paso Robles/Detailed	(6,672)	6,672		
WDT - DRES Quarry 2.3/FT	159			159
R21-Calcom Solar-Western Sky Dairy-DS	(850)	850		
WDT - FT - ZGlobal - Eagle 2 Solar	1,552			1,552
WDT - FT - Morris 385 LLC - Morris 385	2,677			2,677
WDT - FT - El Pomar Parners - El Pomar	831			831
R21 - DS - Chowchilla Dairy Power	(10,000)	10,000		
WDT-FT-ET Solar - Midway Towers Comm Sol	1,705			1,705
WDT-FT-ET Solar - East Bay Community Sol	2,349			2,349
R21 - Musco Olive Biom Gen - Fac Study	(4,729)	4,729		
WDT - SR - El Pomar Partners - El Pomar	(211)	211		
WDT-SR-ForeFront Power-Dulgarian	(250)	250		
WDT - FT - Solar Electric SEPV Cuyama 2	310			310
WDT - SR - Green Light - Eagle 2 Solar	245			245
R21-DS-BNB Renewable-Campbell Soup Supp	5,331			5,331
R21-DIS-Forefront-CDCR-1569-RD	258		(516)	(258)
WDT-SR-Forefront Power-Mouren Farming	558			558
WDT - FT - EPRI - SVUSD Bus Barn Storage	4,326			4,326
R21 - DIS - West Biofuels - SunWest Bio	(688)	688		
R21 - DIS - Syn Tech - Lisa Boone Harris	(4,976)	4,976		
WDT-SIS-Solar Electric-SEPV Cuyama 2	(3,554)	3,554		
R21-DIS-E&J Gallo Winery-Asti Pond Solar	(6,812)	6,812		
R21-DIS-SunPower-EBMUD RESBCT	(41,036)	41,036		
R21-DIS-Maas Energy-Lakeshore Dairy Dig	(7,293)	7,293		
WDT - SIS - Rival Power Peterson Road 2	(5,843)	5,843		
R21 - DIS - JKB Energy-Trinitas Fund II	(2,070)	2,070		
R21-DIS-Concentric-South County Packing	1,099		(1,099)	

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FOOTNOTE DATA

R21-DIS-ARC Alternatives-City of Lincoln	(9,033)	9,225		192
WDT-FT-REP Energy-DRES Quarry 2.4	(69)	69	77	77
WDT-FT-Renewable Prop-Palm Drive Solar C	1,763			1,763
WDT-SR-ET Capital-Midway Towers Comm	(2,500)	2,500		
WDT-SR-ET Capital, Inc. East Bay Com Sol	(2,500)	2,500		
WDT-ISP-Calbio Energy-Bar20 Dairy Biogas	2,628			2,628
WDT-ISP-Calbio Energy-MaddoxDairyBiogas	(4,298)	4,298		
WDT-ISP-Calbio Energy-Double Diamond	(8,414)	8,414		
R21-DIS--SunPower-West Valley Mission Co	(5,185)	5,185		
WDT-SIS-Green Light Energy-Eagle 2 Solar	(3,767)	3,767		
WDT-FT - DG California Solar-Lodi Solar	114			114
R21-DIS-DG Calif Solar, DPIF CA 6 Fresno	(4,132)	4,132		
WDT-ISP-Forefront Power-Nachtigall	(7,771)	7,771		
R21-DIS-ARC Alternatives-County of Kern	(7,473)		7,473	
WDT-SR-Sonoma School-SVUSD Bus Barn Stor	(1,051)	1,051		
WDT-Wireless Sur-Cenergy-NLH1 Solar-0102	190			190
WDT-ISP-Forefront Power-Broadman	(5,952)	5,952		
R21-DIS-Forefront-CA Dept of Corr 23100	(1,883)		1,883	
R21-DIS-Forefront-CA Dept of Corr 23104	(55,018)		55,018	
R21-DIS-Forefront-CA Dept of Corr 23102	(53,666)	53,666		
R21-DIS-Newcomb-City of Fresno(App22373)	(67,879)	67,879		
WDT-EIT-Forefront-1584-WD Mouren Farming	(5,246)	5,246		
R21-DIS-BloomEnergy-KeysightTechnologies	(5,120)	5,120		
WDT-ISP-CEDWhiteRiverSolar2-WhiteRiver2	(5,292)	5,292		
MMA - Collins Pine Repower - ISO 51161	18,085	3,301	(20,984)	401
WDT-SR-RenewProp-1758WD-PalmDriveSolarC	(272)	272		
WDT-FT-Apex Energy/ZGlobal-Jade Solar	(508)	508		
R21-DIS-SiliconVallCleanWater-12kVSwitch	(2,686)	2,686		
WDT-FT-RenewProp-Silveira Ranch Solar C	434			434
WDT-FT-RenewProp-Silveira Ranch Solar D	604			604
WDT-FT-RenewProp-Silveira Ranch Solar A	815			815
WDT-FT-RenewProp-Silveira Ranch Solar B	945			945
WDT-SR: Forefront Power-Rocha-1783-WD	(732)	732		
WDT-ISP: PG&E CoyoteValleyEnergyStorage	14,855			14,855
R21-DIS-Forefront- UCSantaCruz App 23113	(6,732)	6,732		
WDT-FT: Forefront Power - Kern Sunset	(754)			(754)
WDT-FT: Forefront Power - Highway 43	1,190			1,190
WDT-FT: Forefront Power - Beard	(879)	879		
WDT-SR: DG Cali Solar - Lodi Solar	(1,498)	1,498		
WDT-ISP: ETCap-EastBayCommSolar1624-WD	(2,049)	2,049		
R21-DIS:CupertinoElec-WonderfulOrch33018	(5,192)			(5,192)
R21-DIS: EnableEnergy-SpecialtyGran34412	(8,029)	1,629		(6,400)
WDT-FT: Zero Energy - Fallon Two Rock Rd	1,541			1,541
WDT-ISP: Ormat Nevada-Pease Reliability	(9,035)	9,035		
WDT-FCDS: Ormat Nevada-Pease Reliability	(43,633)	4,421		(39,212)
R21-DIS: EnableEnergy-SpecialtyGran34465	(2,117)	3,997		1,880
WDT-SR: Silveira Ranch Solar A	(326)	326		
WDT-SR: Silveira Ranch Solar B	(2,458)	2,458		
WDT-SR: Silveira Ranch Solar C	(2,458)	2,458		
WDT-SR: Silveira Ranch Solar D	(2,458)	2,458		
WDT-SR: Apex Energy - Jade Solar 1865-WD	893			893
WDT-ISP: Solvida - PutahCreekSolarFarmN	(10,000)	10,000		
WDT-FCDS: Solvida - PutahCreekSolarFarmN	5,871			5,871
WDT-FT: BeckwourthGrid-BeckwourthGrid 1	(319)	319		

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FOOTNOTE DATA

R21-DS: Daisy Renew - EarlJohn App 37593	922		922
R21-FS: West Biofuels-SunWest Bioenergy	(6,004)	6,004	
WDT-SR: Forefront Power - Kern Sunset	(150)		(150)
WDT-FT: Kent Solar, LLC - KS Energy	(341)	341	
WDT-SR: Forefront Power - Highway 43	(2,065)	2,065	
R21-DS: CalCom Solar-Moonlight App 38001	(5,552)	5,552	
R21-EIT: West Coast Waste-1827-RD Gen 1	(1,244)	1,244	
R21-DS: Shasta College - Q#1753-RD	(5,865)	5,865	
WDT-CS: Calpine - Cygnus Power Bank	(81,661)	4,421	(77,240)
WDT-FCDS: Calpine - Cygnus Power Bank	(49,580)		(49,580)
WDT-FT: CalCom Solar - Toyon	(460)	460	
R21-DS: NextEra-BigDPacBuildSMF3-Q1791RD	(8,455)	8,455	
WDT-SR: Forefront Power -Beard Q1888-WD	667		667
WDT-EIT: FFPCACommSolar Rocha - 1783WD	(4,313)	4,313	
R21-DS: Ecoplexus-CANatGuard-Q1786-RD	(7,044)	7,044	
R21-DS: Cupertino E-Wonderful Orch 41293	(3,846)		(3,846)
R21-DS: SyntechBioenergy-RiverOakOrchard	(1,214)	1,214	
Repower - Kelly Ridge Powerhouse - SFWPA	11,235		11,235
WDT-CS: Origis Operating-Vaquero Storage	(104,069)		(104,069)
WDT-FCDS: OrigisOperating-VaqueroStorage	(49,374)	4,421	(44,953)
WDT-SIS: Forefront Power - Kern Sunset	(4,078)	4,078	
WDT-SIS: Forefront Power,LLC-Highway 43	(6,676)	6,676	
R21-DS: COofCali DArrigo Bros 114202422	(3,796)	3,796	
WDT-FT: SFPUC-Starr King PV Installation	400		400
R21-DS: BessieDig-HilltopHolsteins 38098	441		441
WDT-SR: Zero Energy Construct-Highway 43	(2,336)	2,336	
WDT-CS: Calpine Corp-Panthera Power Bank	(61,866)		(61,866)
WDT-FCDS: CalpineCorp-PantheraPowerBank	(49,778)	4,421	(45,357)
WDT-CS: Capine Corp-Riverrun Power Bank	(82,345)		(82,345)
WDT-FCDS: CapineCorp-Riverrun Power Bank	(49,778)	4,421	(45,357)
R21-DS: ACElectric-RogerVGroningen 45330	(5,508)	5,508	
WDT-FT: Soltage-Bradley Gillett Solar 1	336		336
WDT-FT:Soltage-San Ardo Pine Vly Solar 1	(318)	318	
WDT-SIS: RenewableProp-SilveiraRanchSolA	1,764		1,764
WDT-SIS: RenewableProp-SilveiraRanchSolB	6,096		6,096
WDT-SIS: RenewableProp-SilveiraRanchSolC	6,229		6,229
R21-DS: PhoenixEner-NapaRecBiomass2MW	(5,943)	5,943	
R21-DS: AmericanCommod-AbelRoadBioenergy	634		(634)
WDT-FT: Engie-Hayward EBCE Array	5,424		5,424
WDT-ISP:Berry Petroleum-Berry NMW Cogens	(46,200)		46,200
R21-DS: AmericanCommod-Willows Bioenergy	(4,133)	4,133	
WDT-FAS: Bar20Dairy - Bar20Dairy1754-WD	(15,000)	15,000	
WDT-SR: PristineSunFund6-RGA2/SH1 Solar	(915)	915	
R21-DS: Sunpower-TheGapInc-App46139NEMMT	(5,218)	5,218	
R21-DS: City of Lincoln (Airport)	(2,163)	2,163	
WDT-EIT/SIS: ForefrontPower-Beard1888-WD	(6,496)	6,496	
WDT-SR: Kent Solar, LLC - KS Energy	(783)		(783)
WDT-SR: SoltageCaDevCo-SanArdoValleySol1	(85)	85	
WDT-SR: Soltage,LLC-BradleyGillettSolar1	631		631
MMA1-NoQ Moss Landing Unit 6-ISO 51164	7,571		7,571
WDT-ISP: CalpineCorporation-CalSunSolar	(65,348)		(65,348)
WDT-FT: GoldenStateRenew-GSRETurkIsland	614		(614)
WDT-FT: GoldenStateRenew - GSRE-OSP	(547)	547	
R21-DS:ArcAlternativesElDoradoUHSD1782RD	(7,938)	7,938	

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FOOTNOTE DATA

WDT-FAS: GreenLightEnergy-Eagle 2 1620WD	(14,753)	14,753		
MMA - QF FrickSummitRepower - ISO 51135	3,309			3,309
R21-DS: Google-MFABayviewFacSolar50088	1,560	201		1,761
WDT-ISP: ZGlobal - Jade Solar_July 2018	2,928			2,928
R21-DS: PhoenixEnergy-NorthForkComPower	11,655			11,655
R21-DS: PhoenixEnergy-BlueMountainElectr	5,436			5,436
R21-DS: West Biofuels - Hat Creek Bioene	2,089			2,089
WDT-ISPreStudy: Strauss Wind Energy, LLC	(19,962)			(19,962)
EGI: Forbestown PH - SFWPA - Testing	342			342
WDT-SIS:Soltag,LLC-BradleyGillettSolar1	(2,016)			(2,016)
R21-DS-BASSLAKEJOINTELESchApp55332RESBCT	(5,338)	5,338		
R21DIS:CityofMaderaRES-BCT (App 54517)	(4,731)			(4,731)
WDT-SIS:Soltag,SanArdoPineValleySolar1	(4,391)			(4,391)
Rule21:DS-MMRConsWAWONAFROZENFOODS-50318	(52,737)	52,737		
WDT-FT-SolarElectricSolution-SEPVBarbar3	84			84
R21:DS-EL DORADO IRRIGATION DISTRICT	(6,568)	6,568		
R21DIS:CA DEPT of CORRECTIONS(App55059)	(52,125)		52,125	
WDT-FT-WildcatRenewableRPSantaCruzSolar1	753		(1,553)	(800)
WDT-FT-WildcatRenewableRPSantaCruzSolar2	825		(1,625)	(800)
Rule21:DS-JKB EnergySierraPacificAP55806	(51,997)			(51,997)
WDT-FT-ApexEnergySolutionsGasCoRdSolar1	(655)			(655)
MMA #5 - Q1036 Mustang 2 - ISO 51601	(181)			(181)
WDT-SR-GoldenStateReneEng-GSRETurkIsland	(2,500)	2,500		
Rule21:DS-DeltaDiabloCo-Digestion1968-RD	(3,390)	3,390		
WDT-FastTrack-Universal Solar-USPPGE9918	(664)	664		
WDT-FastTrack-Universal Solar-USPPGE8918	(664)	664		
WDT-FastTrack-Universal SolarUSPPGE-7918	(801)	801		
WDT-FastTrack-Universal Solar-USPPGE6918	(879)	879		
WDT-FastTrack-Universal Solar-USPPGE4918	(879)	879		
WDT-FastTrack-Universal Solar-USPPGE3918	(515)	515		
WDT-Fas Track-Universal Solar-USPPGE2918	(801)	801		
WDT-Fast Track-UniversalSolar-USPPGE1918	(262)	262		
WDT-FT-NatelEnergyc/oKinetMurphyHydro	(317)	317		
WDT-FT-RENESOLAPOWERHOL-OspreySolar	282		(282)	
WDT-PS-UticaWater&Power(UWPA)-AngelPower	(1,640)	1,640		
WDT-FT-ReneSolaPowerHoldingsTaylorSolar	509			509
R21-Detailed Study-STAMOULES PRODUCE	(6,900)	6,900		
Rule21DSBerryPetroleumCompy-BerryCogen18	538			538
WDT#SR-CITYOFHAYWARDHaywardEBCEArray	(2,500)	2,500		
MMA-Q1278-Westwood Energy Ctr-ISO 52013	5,059			5,059
WDT:FT - Pine Flat Solar 1 - Apex Energy	(475)	475		
WDT:FT - Merced 3 - Apex Energy	(282)	282		
WDT-FastTrack-Calcom Solar-Sycamore-Napa	3,853			3,853
WDT-SIS- Kent Solar-LLC-KS Energy	4,336			4,336
WDT-SR-RenewableRPSantaCruzSolarQ2031WDT	(472)		472	
WDT-SR-RenewableRPSantaCruzSolar1Q2030WD	(472)		472	
R21#Detailed Study-Superior Packing Co.	(7,323)			(7,323)
R21:DS:NextEraEnerg114971313DGCAWestside	(54,588)		54,588	
WDT-ISP/FCDS-DGCal-YubaCityEnergyStorag	(8,166)			(8,166)
R21-DS: CH4 Green Energy CDE 4		2,009		2,009
WDT:FT - Corda I - Cratus Energy Mgmt	1,076		(1,076)	
WDT:FT - Corda II - Cratus Energy Mgmt	1,076			1,076
WDT:FT - Gonzales - FFP CA Com Solar	(455)	455		
WDT:FT - Washoe Ave - FFP CA Com Solar	3,550			3,550

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FOOTNOTE DATA

WDT:SR - Osprey Solar - Renesola Power	(2,392)	2,392		
R21:DS: WonderfulPistachios&Almonds66478	(49,389)	201	49,188	
R21:DS: Wonderful Pistachios & Almonds	(9,295)			(9,295)
MMA2 - Q1106 Fountain Wind - ISO 51770	(60)			(60)
WDT:ISP - Tranquility - FFP CA Com Solar	(6,971)	6,971		
WDT:ISP - Munoz - FFP CA Com Solar	(4,827)			(4,827)
R21:DS: WonderfulPistachios&Almonds67792	(4,837)			(4,837)
WDT:SR - 2040-WD - Gas Co Road Solar 1	306			306
R21:DS - City of San Jose (App 68019)	(55,283)	3,759		(51,524)
WDT:ISP - Leo Solar - Apex Energy	(7,979)			(7,979)
R21:DS - RWA/UCM Cogen-Merced Co RWM	(10,000)	10,000		
R21:DS: MacphersonOil-RoundMountainSolar	(10,000)	12,441		2,441
WDT-SR: SycamoreGroup-SycamoreNapa2066WD	(1,742)			(1,742)
WDT-FillInStudyReneSolaPowerTaylorSolar	(2,210)			(2,210)
MMA1 - Q1239 Medeiros Solar - ISO 40030	5,417	3,906		9,323
WDT-FT-ApexEnergySolutionsPineFlatSolar2	(824)			(824)
WDT-FT-ApexEnergySolutionGasCoRoadSolar2	(557)			(557)
WDT-SR-SolarElectricSolutionSEPVBarbara3	(2,282)			(2,282)
WDT-SR-Kinet Inc-Murphys Afterbay Hydro	3,643		(1,143)	2,500
Rule21:DS-GRANITEROCKCOMPANY(App69212)	(1,756)			(1,756)
WDT:SR-Manning Avenue-FFP CA Com Solar	(1,705)	1,705		
Rule21-DS-ChicoElectricRoplastApp#4959	(1,716)			(1,716)
WDT-FT-Apex Energy Solutions-Lara Solar	(284)			(284)
WDT-FT-Apex Energy Solutions-Leo Solar2	(749)	749		
WDT-FT-FFPCACommunitySolarBroadman2	(782)			(782)
WDT-SR-ApexEnergySolutionsPineFlatSolar1	(1,670)	1,670		
Rule21DS-GOLDENSTATEFC-App71807	(767)			(767)
WDT-FT-ApexEnergySolutionsPineFlatSolar3	(697)	697		
WDT-FT-UniversalSIAircoupeSolar3((30N27)	36			36
WDT:SR - 2083-WD-Corda 1 - Cratus Energy	(578)		578	
WDT:SR - 2084-WD-Corda II-Cratus Energy	(578)			(578)
WDT-FT-ApexEnergySolutionsLLCLEoSolar3	(636)			(636)
WDT:FT - WHI Solano R&D - Wind Harvest	(1,000)	1,000		
R21:DS - Fowler Packing Co - App 76191	(7,678)			(7,678)
R21:DS - Fowler Packing Co - App 76185	(5,408)			(5,408)
WDT:SIS - Osprey Solar - Renesola Power	(1,127)		1,127	
MMA1 - Q1010-Dyer - ISO 51539	(392)	799		407
WDT-FillInStudyApexEnergySolutiJadeSolar	(9,237)			(9,237)
WDT-SR-FFPCACommunitySolar-WashoeAvenue	(918)			(918)
WDT-SR-ApexEnergySolutionsGasCoRdSolar2	(2,112)			(2,112)
WDT-SIS-ApexEnergySolutioGasCoRoadSolar1	(4,984)			(4,984)
WDT-ISP-CES Electron Farm One,LLC	44			44
WDT-SIS-ReneSolaPowerHoldingLLCBroadman2	(5,184)			(5,184)
WDT-Fast Track-Division Solar-Lake Solar	(554)			(554)
WDT-IS-RenewablPropertiesLakeHermanSolar	(2,288)			(2,288)
Rule21DS-ATS-KaiserDublinHUBCancerCenter	(3,374)			(3,374)
WDT-SR-ApexEnergySolutionsLeoSolar3	(2,500)			(2,500)
WDT:FT - Corda III - Cratus Energy Mgmt	348			348
WDT:FT - Lara Solar - Apex Energy Solar	(53)			(53)
WDT-FT-EDFRenewablesEDF-DSSeaBreezeSolar	6,059			6,059
WDT-FT-Elie MehrdadTrustsolaparkphaseA	44			44
MMA - Q1363-Sandhill C - ISO 53028	(281)			(281)
WDT-SIS-CratusEnergyManagementCorda1	3,567		(3,567)	
WDT-SIS-CratusEnergyManagementCorda2	(7,067)			(7,067)

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FOOTNOTE DATA

Rule21:DS-SUNNYGEMLLC(App 84294)NEMExp	(8,024)			(8,024)
WDT-SIS-FFPCACommunitySolarWashoe Avenue	2,328			2,328
WDT-IS-Cratus Energy MGMT-Corda IV	(3,461)			(3,461)
WDT-IndepFullCapacity-VESI10-ErisStorage	(50,554)	785		(49,769)
WDT-IS-esvolta-Ip-TierraRobleEnerStorage	(53,693)			(53,693)
WDT-FT-RenewableProper-SoscolFerrySolarA	176			176
WDT-FT-RenewableProper-SoscolFerrySolarB	176			176
WDT-FT-RenewableProp-ByronHotSpringSolar	552			552
Rule21:DS-UNIVERSITYOFTHEPACIFICApp83342	(2,011)	1,234	777	
WDT-IS-JATONLLC-KecksRoadSolarFacility	(7,851)			(7,851)
WDT-FT-RenewableProperti-WilsonHillSolar	1,043			1,043
Rule21-DetailedStud-SpecialtyGranulesINC	(13,633)			(13,633)
R21:DS - SunWest Bioenergy - 2076-RD	(9,629)	784		(8,845)
WDT:FT-Gas Co Road Solar 3-Apex Energy	(1,000)			(1,000)
WDT:FT-Gas Co Road Solar 4-Apex Energy	(1,000)			(1,000)
WDT:SIS-Gas Co Road Solar 2-Apex Energy	(8,749)			(8,749)
MMA - Q1143-Alpaugh Storage - ISO 51720	(60)			(60)
R21:DS - Specialty Granules - 1912-RD	(13,693)			(13,693)
WDT-FTCratusEnergyManagement-Mendoza	269			269
WDT-Cluster12-CalPine-CalSunSolar2004-WD	(49,824)			(49,824)
WDT-FullCapacity-VESI11LLC-Eris Storage	(49,783)			(49,783)
WDT:ISP-Redwood Coast Airport Microgrid	(1,665)			(1,665)
WDT-FT-GoldenStateRenewable-HuronStorage		(101)		(101)
WDT-IS-esvolta-IpTierraRobleIIEngStorage	(55,521)	4,260	51,260	
Rule21:DGS-CorcoralIrrigationDistrict-5MW	(6,682)		6,979	297
WDT-SR-ZGlobal-Lara Solar 2 (2142-WD)	975			975
Rule21:Detailed Study-City of Manteca	(2,741)	801		(1,940)
WDT-SR-RenewableProperti-WilsonHillSolar	1,184			1,184
WDT-IS-SunPower-UCSFDentalClinics/Cogen	(57,974)	184	57,790	
Rule21-DS-GRIMMWAYENTERPRI-11412MALAGARD	(4,774)	786		(3,988)
WDT-FTBloomENGPosoCreekFamilyDairyBiogas	(753)			(753)
WDT-ISBloomENGSouthpointRanchDairyBiogas	(5,112)	1,255		(3,857)
WDT-SR-RenewableProper-SoscolFerrySolarB	(1,814)			(1,814)
WDT-SR-RenewableProper-SoscolFerrySolarA	(1,814)			(1,814)
WDT-SR-RenewablePro-ByronHotSpringsSolar	(1,814)			(1,814)
MMA-Q1269 Capetown Wind (BESS)-ISO 51972	1,230			1,230
EGI:Facilities Study - Santa Clara Wind	(4,287)	941		(3,346)
EGI:Facilities Study - Forebay Wind	(3,463)	528		(2,935)
Rule21-DS-Windpower-Dole5.6MWWindTurbine	(52,588)		52,588	
WDT-FT-SunwalkerEnergy-ByronSolarFarmLLC	3,108		(3,108)	
Rule21:DS:MESAWater-BerrendaMWD-StationA	(54,423)	4,493		(49,931)
EGI:Facilities Study - Collins Pine Co.	5,835			5,835
Rule21:DS-CALIFORNIARESOURCECORPORATION	(9,325)			(9,325)
Rule21-DS-TIMIRAN INC-Huller Add-On	(4,569)			(4,569)
WDT-Clu12FCDS-Solvida-PutahCreekFarNorth	(49,929)	145		(49,785)
WDT-IS-ConflittiEnergy-CESElectroFarmOne	(9,167)	6,137		(3,030)
MMA - Q1235 Hudson Solar 1 - ISO 51904	(192)			(192)
Rule21:DetailedStudy-WAL-MART STORES INC	(8,525)			(8,525)
WDT-SR-ApexEnergySolutionGasCoRoadSolar3	2,510			2,510
WDT-SR-ApexEnergySolutionGasCoRoadSolar4	(811)			(811)
CCSF Warnerville Sub Rehab	(35,043)			(35,043)
WDT-SR-EDFRenewables-EDFDSSeaBreezeSolar	2,284			2,284
Rule21:DS-FallRiverRCD-McArthurBioenergy	4,702	872		5,574
WDT-IS-Dimension CA 1 LLC-G3FarmingTrust	(47,140)			(47,140)

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NextEra Honey Lake Solar DTT	1,155			1,155
Rule21:DS-OLAM WEST COAST-Olam-Firebaugh	(2,254)	2,123		(132)
WDT-IS-SonomaValleySVUSDBusBarnCAISO	(9,052)			(9,052)
WDT-FT-RenewableProper-SoscolFerrySolarC	(411)			(411)
WDT-FT-RenewableProper-SoscolFerrySolarD	496			496
WDT-SIS-RenewablePr-ByronHotSpringsSolar	(6,706)			(6,706)
Rule21:DS-RWA/UCMCOGENERATION(App104269)	(7,618)	7,575		(42)
Rule21:DS-RWA/UCMCOGENERATION(App104272)	(10,000)			(10,000)
Rule21:DS-CityofMaderaWWTP-RES-App103889	(638)			(638)
WDT-EIT-Byron Solar Farm LLC 2	5,192	2,000	(7,192)	
WDT-SR-Bloom-PasoCreekFamilyDairyBiogas	(1,815)			(1,815)
MMA-Q557-CED White River West2-ISO 50555	(1)			(1)
Rule21:DS-LionBrotherNewstone(App106347)	(3,954)	1,939		(2,015)
WDT-EIT/SIS-ApexEnerg-LaraSolar2-2142-WD	(5,171)	453		(4,718)
WDT-IS-EC&R SolarDevelopment LLC-Lipizan	(57,578)			(57,578)
WDT-FT-Renewable-HatcheryRoadSolarB	489			489
WDT-FT-Renewable-HatcheryRoadSolarA	489			489
WDT-SR-Renewable-Soscol Ferry Solar D	(1,862)			(1,862)
WDT-SR-Renewable-Soscol Ferry Solar C	(1,419)			(1,419)
WDT-SR-DivisionSolar-Lake Solar(2137-WD)	(2,021)			(2,021)
WDT-FT-NapaJamiesoCanyon-NapaSelfStorage	3,587			3,587
WDT-FT-GCLNewEnergyHartleySubstation	228			228
WDT-FT-GCLNewEnergyPlumasSubstation	163	2,371		2,534
WDT-FT-Dimension CA1-CA-19-0024-Jorge	(99)			(99)
WDT-ISP-ApexEnergySoluti-GasCoRoadSolar3	(8,325)			(8,325)
WDT-ISP-ApexEnergySolutio-GasCoRoadSola4	(7,677)			(7,677)
Rule21:DS-Main Campus Solar (App 111253)	(7,379)	4,630		(2,749)
Rule21:DS-DREYERSNestleBakersfiApp111016	(10,000)	12,643		2,643
R21-DS-J R SIMPLOT COMPANY INC	(9,463)	5,779		(3,684)
WDT-FT-SaltbrushPlainsLLC-SaltbrushPlain	374			374
Rule21:DS-GCLNew-2199-RDBESSGonzaleBank3	(7,832)			(7,832)
Rule21:DS-GCLNew-2200-RDBESSGonzaleBank4	(7,464)	185		(7,279)
Rule21-DS-CARESOURCESPRODUCTI-CRC-MtPoso	(59,188)	7,537		(51,651)
Rule21-DS-PlanetaryVentureMFABayviewFac	(9,456)	1,176	8,281	
WD-FT-SonomaUniScho-SVUSD-BusBarnCAISOII	3,558	6,944		10,502
Rule21-DS-FostPoulFmsFosterTravelFeedMil	(9,830)	4,440		(5,390)
Rule21-DS-FresnoFarming-FosterBelgravia	(9,830)	1,108		(8,722)
WDT-SR-RenewableProp-HatcheryRdSolarA	1,836	603		2,439
WDT-SR-RenewableProp-HatcheryRdSolarB	2,196	603		2,799
Rule21-DS-SFSpiceCo-BrightPeopleFoods	(4,342)	1,477		(2,865)
Rule21-DS-TracyDesalinationProj116685552	(9,282)	7,933	1,349	
WDT-FT-RenewablePropByronHighwaySolar	(5,260)	1,391		(3,868)
WDT-FAS-RedwoodCoastAirportMicrogrid	(13,989)			(13,989)
MMA-Q779-WRIGHT SOLAR-ISO 50712	33,442	(30,480)	(2,962)	
Rule21-DS-Toma Tek Inc	(9,101)	11,440		2,339
Rule21-DS-Amazon.com-Amazon BFL1	(7,203)	2,594	4,610	
Rule21-DS-AriesLostHillsBioenergy	(10,000)	4,648	5,352	
WDT-FT-GoldenStateRenewEnergy-ColmaSolar	328	339		667
WDT-FT-Vesi14LLC-CeresEnergyStorage	(58,593)	13,000		(45,593)
WDT-FT-ColdwellSolar1,LLC,RobinsonSolar	4,136	907		5,043
WDT-FT-Dimension CA 1 LLC-Jacobs 1	2,186			2,186
WDT-FT-Dimension CA 1 LLC-Jacobs 2	1,480			1,480
WDT-FT-ApexEnergySolutionsLLC-JadeSolar3	3,512	1,167		4,678
MMA-Q1441-Kernridge Expansion-ISO 43007	4,458	466		4,924

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WDT-SR-SonomaUniSch-SVUSD BusBarnCAISO	(572)			(572)
MMA-Q1272-Cascade Energy Storage-ISO 519	323			323
WDT-SR-NapaJamiesonCnynNapaSelfStorage2	(671)			(671)
WDT-FT-Hayworth/Fabian LLC-Oakley 3	(326)			(326)
WDT-FT-Dimension CA 1 LLC-Henrietta	1,918			1,918
WDT-FT-Dimension CA 1 LLC-Wellfield	779			779
WDT-FT-Dimension CA 1 LLC-EMH	(59,780)	15,517	44,262	
WDT-FT-GclSysIntegrn-BessUpperLake	1,046	933	(1,980)	
WDT-FT-GclSysIntegrn-BessWillits	541		(541)	
WDT-FT-GclSysIntegrn-BessMolino	1,046		(1,046)	
WDT-FT-GclSysIntegrn-BessHopland	1,046	933	(1,980)	
WDT-ISP-Dimension CA 1 LLC-Jorge	(9,326)	10,577		1,250
WDT-FT-Dimension CA 1 LLC-Mendoza	935			935
EGI:FacilitiesStudy-sPowerAltamontMidway	(8,570)	1,488		(7,082)
WDT-SR-ColdwellSolar1,LLC-Robinson Solar	(2,500)			(2,500)
MMA-Q1028 & Q1029-Little Bear1-ISO 51587	720	240	(960)	
MMA-Q1235-Hudson Solar 1-ISO 51904	773	113	(886)	
WDT-FT-ApexEnergySolutions-NicoleSolar1	1,193	1,401	(2,594)	
WDT-FT-ApexEnergySolutions-NicoleSolar2	313	302	(615)	
WDT-FT-ApexEnergySolutions-PineFlat1	581	790		1,370
WDT-FT-ApexEnergySolutions-PineFlat2	1,021	605		1,625
Rule21-DS-GILLIG LLC-GILLIG LLC	(10,000)			(10,000)
WDT-SR-GclSysIntegTechnology-BessPlumas	(2,500)	576		(1,924)
WDT-FT-GclSysIntegTechgy-MarysvilleBESS	(1,000)	462		(538)
WDT-FT-GclSysIntegTechgy-Cotati BESS	(833)	737		(96)
WDT-FT-ZeroEngyCnstFallonTwoRockRdSolar	(833)	340		(493)
WDT-FT-DimensionCA1AlpaughDacSolar1103	144			144
WDT-FT-GldnStatRnwEngyGsreColmaStorage	1,296	2,673	(3,969)	
Rule21-GoldenStateFcLlc-SCK1 Amazon	(9,334)	5,978		(3,356)
WDT-FT-GldnStatRnwEngy-ColmaLithiumIon	917		(917)	
Rule21:DS:SENTINELPEAKRESCA-HopkinsSolar	(10,000)	1,271		(8,729)
WDT-FT-Borrogo-EarthquakeProtnSystems	(10,000)	12,982		2,982
MMA-Q1036-RE Mustang 2-ISO 51601	480	2,584	(3,064)	
WDT-SR-GsrEnergy-GsreColmaSolar2317-WD	(1,047)			(1,047)
MMA-Q877-CA Flats-ISO 51211	533	6,815		7,348
WDT-ISP-FresnoDisadvantagedCommunitySola	(70,000)	11,522		(58,478)
WDT-SR-ApexEnergySolutions-JadeSolar3	(2,500)			(2,500)
WDT-EIT--RenewableProp-HatcheryRdSolarB	(8,708)	861		(7,847)
WDT-EIT--RenewableProp-2296WDB ByronHwy	1,190	3,625		4,815
WDT-EIT--RenewableProp-HatcheryRdSolarA	(8,708)	861		(7,847)
Rule21-DS-Chevron-LostHills_Storage	(84,000)	18,466		(65,534)
WDT-SR-GclNewEnergyBessLuchettiQ#2299-WD		1,349	(2,500)	(1,151)
WDT-CSP-Carbonera-Carbonera3HybridSolar		696	(696)	
WDT-SR-Hayworth/Fabian-Oakley3#2333-WD	(2,500)	1,260		(1,240)
WDT-ISP-Dimension CA 1 LLC-Mendoza	(10,000)	8,059		(1,941)
WDT-ISP-Dimension CA 1 LLC-Henrietta	(10,000)	6,606		(3,394)
MMA-Q1103-Central 40-ISO51821	261	3,343		3,604
MMA-Q1117-Aquamarine Westside-ISO51817	261	890		1,151
MMA-Q1141-Alamo Springs 1-ISO51745	355	5,625	(5,980)	
MMA-Q1157-Alamo Springs 2-ISO51708	355	4,502	(4,857)	
MMA-Q1242-Pluot-ISO52008	261	234		495
MMA-Q1391-Sonrisa-ISO53017	1,046	6,635	(7,335)	346
MMA-Q272-American Kings Solar-ISO50212-C	434		(434)	
MMA-Q779-Wright Solar-ISO50712	439	6,390	(5,355)	1,474

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MMA-Q946-Northern Orchard Solar-ISO51400	1,821	6,246	(8,067)	
MMA-Q954-Fifth Standard Solar-ISO51419	1,649	6,254	(7,902)	
MMA-Q1036-Mustang 2-ISO51601	267	872	(1,139)	
MMA-Q1223-American kings 9-ISO51935	173	5,899	(6,072)	
MMA-Q1259-NorthernOrchardSolar2-ISO51918	173		(173)	
MMA-Q1350-Beltran Central Solar-ISO53069	267	12,546		12,813
MMA-Q1379-Heartland 1-ISO53048	267	10,466	(8,139)	2,593
MMA-Q1380-Hearland 2-ISO53042	958	9,378	(7,570)	2,766
MMA-Q1382-Las Camas 1-ISO53030	2,773	6,817	(9,236)	354
MMA-Q1455-Janus-ISO53174	1,130	6,517	(7,647)	
MMA-Q643W-Re Mustang-ISO50630	267	5,869	(4,897)	1,239
MMA-Q643X-Re Tranquility-ISO50647	958	5,518	(5,057)	1,419
MMA-Q1120-Chestnut Westsdie-ISO51818	267	392		659
MMA-Q1129-Luna Valley-ISO51746 (Batch)	267	13,320	(7,139)	6,448
MMA-Q1139-Westlands Solar Blue-ISO51815	267	400		667
MMA-Q1244-Proxima Solar-ISO51980	267	11,653	(11,920)	
MMA-Q1392-Warriors Solar-ISO53025	355	2,830	(3,185)	
MMA-Q1394-Driftwood Stella-ISO53051	355	4,834	(5,189)	
MMA-Q1397-Sandrini Sol 1-ISO53026	1,046	3,942	(4,988)	
MMA-Q1443-Angela-ISO53205	267	7,385	(7,651)	
MMA-Q1444-Beauchamp Solar-ISO53234	267	4,645	(4,911)	
MMA-Q1456-Las Camas 3-ISO53203	1,218	5,175	(6,040)	354
MMA-Q1493-Azalea-ISO53229	267	3,841	(4,107)	
MMA-Q1499-Jasmine-ISO53164	267	4,035	(4,301)	
WDT-ISP-Dimension CA 1 LLC-Jacobs 1	(10,000)	7,284		(2,716)
WDT-ISP-Dimension CA 1 LLC-Wellfield	(10,000)	13,127	(3,127)	
WDT-ISP-DimensionCA1-AlpaughDacSolar1003	(10,000)	6,723		(3,277)
WDT-ISP-Dimension CA 1 LLC-Jacobs2	(10,000)	7,146		(2,854)
WDT-SR-Q#2352-WD GSRE Colma Storage	(2,500)	1,743	757	
WDT-SR-Q#2342-WD BESS Upper Lake	(2,500)	737		(1,763)
WDT-SR-Q#2343-WD BESS Hopland	(2,500)	2,035		(465)
WDT-SR-Q#2344-WD BESS Willits	(2,500)	1,223		(1,277)
WDT-SR-Q#2345-WD BESS Molino	(2,500)	1,223		(1,277)
WDT-SR-Q#2354-WD BESS Johnson	(2,500)			(2,500)
WDT-SR-Q#2356-WD BESS Lafford	(2,500)	1,290		(1,210)
WDT-FT-GldnStRenewEngr-DalyCityStorage		704	(1,000)	(296)
WDT-FT-Borrego-NorthCoastHwySolar1		890	(890)	
WDT-FT-Borrego-NorthCoastHwySolar2		813	(357)	456
WDT-SR-Q#2288-WD Saltbrush Plains	(2,500)	1,912		(588)
MMA-Q272-American Kings-ISO50212-C	320	2,833	(3,152)	
Rule21-DS-Wonderful Firebaugh		4,764	(10,000)	(5,236)
R21-App141055-Wonderful Kings		1,564	(10,000)	(8,436)
R21-DS-App142457AtwaterWWTP-ResBctSystem		12,458	(10,000)	2,458
R21-DS-App142877-Sunnygem Huller		686	(10,000)	(9,314)
WDT-FT-Victoria Lane Solar		737	(1,000)	(263)
WDT-FT-River Bar Road Solar A		1,257	(1,000)	257
WDT-FT-River Bar Road Solar B		1,257	(1,000)	257
R21-DS-App143441-Danell Bros Inc		5,015	(10,000)	(4,985)
MMA-Q1010-DyerSummitWindRepower-ISO51539		392	(392)	
WDT-SR-Q#2365-WD-FallonTwoRockRoadSolar		553	(2,500)	(1,947)
MMA-Q1111-DiabloEngy/BlckDiamnd-ISO51798		5,924		5,924
WDT-FT-TrueLeafInterconnectionExport		604	(1,000)	(396)
R21-DS-2291RD-CalResourcesProductionCorp		4,044	(10,000)	(5,956)
R21-DS-2300RD-CRC Yowlumme 2 South		2,447	(10,000)	(7,553)

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WDT-FT-GSRE Clear Lake Solar		75	(29)	47
WDT-FT-ApexEnergySolutions-LeoSolar1			(1,000)	(1,000)
WDT-FT-ApexEnergySolutions-LeoSolar2			(1,000)	(1,000)
R21-DS-152525-CaResrcesPrdn-SW 24 28 27		13,342	(86,000)	(72,658)
WDT-FT-Electra SES 1-Electra SES 1		576	(576)	
WDT-SR-2399WD-NorthCoastHwySolar 1		1,183	(1,183)	
WDT-SR-2400WD-NorthCoastHwySolar 2		922	(922)	
WDT-SR-Q#2366-WD-GSRE ColmaSolarIon		3,218	(3,218)	
R21-DS-155121-Wonderful HS		192	(10,000)	(9,808)
MMA-Q1270-Corby-ISO51915		167	(167)	
MMA-Q1350-BeltranCentralSolar-ISO53069		167	(167)	
R21-DS-154968-Sealed Air Madera		5,867	(10,000)	(4,133)
MMA-Q1472-Dallas Energy Storage-ISO53162		16,596		16,596
R21-DS-153273-SCIF- Vacaville Carports		2,947	(10,000)	(7,053)
WDT-IS-2299WD-BESS Luchetti		6,838	(10,000)	(3,162)
WDT-ISP-Vesi11 LLC-Eris Storage		1,229	(58,000)	(56,771)
WDT-FT-CMSA CogenSystemUpgrade		459	(459)	
WDT-SR-2417WD-TrueLeafIntconnectionExpt			(2,500)	(2,500)
WDT-ISP-2313WD-BessPlumas		1,167	(10,000)	(8,833)
WDT-ISP-2354WD-BESS Johnson		5,380	(10,000)	(4,620)
WDT-ISP-2356WD-BESS Laffond		711	(10,000)	(9,289)
R21-DS-159578-CityofMaderaWWTP RES-BCT		8,011	(8,011)	
WDT-FT-GSRE Clear Lake		1,106	(1,106)	
WDT-ISP-Saltbrush 10		16,174	(60,000)	(43,826)
WDT-ISP-DimensionCA1LLC-CorcoranBESS		184	(184)	
MMA-Q1136-Westlands Almond-ISO51828		10,300	(10,300)	
R21-DS-2387RD-HalliburtonEnergyServices		5,040	(5,040)	
WDT-ISP-2343WD-BESS Hopland		3,818	(10,000)	(6,182)
WDT-ISP-2342WD-BESS Upper Lake		4,252	(10,000)	(5,748)
WDT-C13 FCDS-Eris Storage			(50,000)	(50,000)
WDT-C13 FCDS-Saltbrush 10		517	(50,000)	(49,483)
WDT-FT-Humboldt Community Solar		997	(1,000)	(3)
WDT-ISP-Hatchery Road Solar C		7,848	(10,000)	(2,152)
WDT-FT-Stockdale Dairy Biogas		576	(1,000)	(424)
WDT-ISP-Hatchery Road Solar D		7,712	(10,000)	(2,288)
MMA-Q1540-Plano Storage-ISO40047		1,664		1,664
MMA-Q1539-Irving Storage-ISO40046		1,667		1,667
R21-DS-APP162754-Mendota Hydrogen		2,180	(123,000)	(120,820)
WDT-SR-2434WD-Leo Solar 1		1,810	(2,500)	(690)
WDT-SR-2435WD-Leo Solar 2		1,810	(2,500)	(690)
WDT-C13 FCDS-Stodola BESS		6,756	(50,000)	(43,244)
WDT-CLUSTER-Stodola BESS		4,621	(60,000)	(55,379)
WDT-FCDS-2378WD-EarthquakePrtnSyst		1,130	(50,000)	(48,870)
MMA-Q1443-GentleLineRouteProp-ISO53205		7,576	(7,576)	
WDT-ISP-Callisto2Storage50MW		155	(100,000)	(99,845)
WDT-C13 FCDS-Callisto2Storage50MW		32,793	(50,000)	(17,207)
WDT-ISP-North Coast Highway Solar 2		3,766	(10,000)	(6,234)
R21-DS-Rodeo Solar-NextEraEnergy		5,376	(82,000)	(76,624)
WDT-C13 FCDS-CliftonCourtSolar		234	(50,000)	(49,766)
WDT-CLUSTER-CliftonCourtSolar		3,981	(10,000)	(6,019)
R21-DS-ParreiraAlmondProcessingAddOn		5,333	(10,000)	(4,667)
R21-DS-2404RD-Lindt&SprungliNorthAmerica		4,326	(10,000)	(5,674)
MMA-Q1129-Luna Valley-ISO51746 (COD)		498		498
R21-DS-181109-CityOfAtwaterWWTP-NEMEXP		3,978	(10,000)	(6,022)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

FOOTNOTE DATA

WDT-ISP-PV Byron EG-I	2,047	(2,047)	
EGI:TO-FS-LSPGCGatesInterconnection	128,665	(50,000)	78,665
WDT-ISP-FS Solar LLC	533	(10,000)	(9,467)
WDT-SR-2477WD-HumboldtCommunitySolar	1,034	(1,034)	
WDT-SR-2469WD-GSRE Clear Lake Solar	1,326	(1,326)	
R21-DS-168902-Bulseye Farms Huller	2,020	(2,020)	
R21-DS-166625-Cabrillo College	3,317	(10,000)	(6,683)
WDT-C13 FCDS-2226WD-CesElectronFarmOne		(50,000)	(50,000)
WDT-C13 FCDS-2322WD-CeresEnergyStorage	192	(50,000)	(49,808)
WDT-FT-Freedom Pass Storage		(150,000)	(150,000)
WDT-C13 FCDS-Freedom Pass Storage	9,933	(50,000)	(40,067)
MMA-Q267-Lodi Energy Center-ISO50204	1,192		1,192
WDT-SR-2472WD-Electra SES 1	2,002	(2,500)	(498)
R21-DS-10695 DECKER AVE		(10,000)	(10,000)
R21-DS-Bakersfield College	992	(10,000)	(9,008)
WDT-SR-2482WD-Stockdale Dairy Biogas	157	(2,500)	(2,343)
WDT-FT-Callisto Storage 4 MW	647	(647)	
R21-DS-168920-WonderfulPomBeverage	4,511	(10,000)	(5,489)
R21-DS-174317-WonderfulPomJuice	1,669	(10,000)	(8,331)
R21-DS-174316-WonderfulPomPlant 2	4,494	(10,000)	(5,506)
MMA-Q1103-Central40(Modification)-ISO518	1,827	(1,107)	720
WDT-FT-Bar20 Biogas Fuel Cell	569	(1,000)	(431)
R21-DS-175509-LegacyPackingDetailedStudy	4,800	(10,000)	(5,200)
WDT-FT-119016704-Madena Solar 3	1,819		1,819
WDT-ISP-119016745-Madena Solar 1	10,528	(10,000)	528
WDT-ISP-119016822-Madena Solar 2	11,029	(10,000)	1,029
R21-DS-174371-Wonderful POM Plant 1	1,263	(10,000)	(8,737)
WDT-FT-119036004-MarshallRanchFIT500KW	4,497	(4,497)	
WDT-SR-2474WD-CMSA CogenSystemUpgrade	1,570	(1,570)	
WDT-ISP-119057258-County Road 18	990	(10,000)	(9,010)
WDT-ISP-119057480-Woodland Gravel Mine	503	(163)	340
WDT-ISP-2434WD-Leo Solar 1	1,433	(10,000)	(8,567)
R21-DS-178632-CrainWalnutCWS2 NEMA	708	(10,000)	(9,292)
WDT-ISP-2533WD-Madena Solar 3	1,488	(10,000)	(8,512)
R21-DS-178840-TaftEnergyProjects-NEMMT	1,113	(10,000)	(8,887)
WDT-ISP-119130671-UticaAveSolarFacility	9,025	(10,000)	(975)
R21-DS-182177-Madera WWTP-NEMExp	3,174	(10,000)	(6,826)
R21-DS-179034-SierraPacificInd-ChinCamp	14,649	(10,000)	4,649
R21-DS-2411RD-UC DavisArray2BldgE2.3		(10,000)	(10,000)
WDT-FT-119164447-Glendale Drive Solar	1,127	(1,127)	
R21-DS-164184-ArdaghMaderaSolarNEMA	20,026	(60,000)	(39,974)
R21-DS-177618-BerkeleyLabPSPS-EmgPwr	17,607	(10,000)	7,607
EGI:TO-FS-LS Power-Round Mountain	165,874	(75,000)	90,874
WDT-ISP-119292303-ZGlobalElectraSES1	2,583	(10,000)	(7,417)
WDT-ISP-119304283-Apex-Merced BESS	4,920	(10,000)	(5,080)
R21-DS-185649-351BelleHavenDr-NEMexp	20,077	(58,000)	(37,923)
WDT-ISP-119339344-Apex-Pine Flat 1	2,637	(10,000)	(7,363)
WDT-ISP-119340651-Apex-Pine Flat 2	1,530	(10,000)	(8,470)
WDT-SR-2517WD-Callisto Storage 4 MW	1,060	(1,060)	
WDT-SR-2544WD-MarshallRanchFITsolar500KW	1,913	(1,913)	
WDT-FT-119294847-RailroadWintersCleanPwr	284	(109)	175
R21-DS-119067993-CAB000.0, BAR20	1,606	(10,000)	(8,394)
R21-DS-118650627-Anthony Vineyards	1,964	(10,000)	(8,036)
WDT-FAS-2378WD-Creed Road Solar 1		(15,000)	(15,000)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

FOOTNOTE DATA

WDT-ISP-119462082-505 Solar	1,492	(10,000)	(8,508)
WDT-ISP-119516120-GibsonSolarProject	185	(185)	
R21-DS-198456-SE SURFACE WTP NEMMT	13,968	(10,000)	3,968
R21-DS-198470-Clovis Regional WWTP NEMPS	12,218	(65,000)	(52,782)
WDT-ISP-119563843-Pine Flat 3	591	(10,000)	(9,409)
WDT-ISP-119563984-Pine Flat 4	987	(10,000)	(9,013)
WDT-ISP-2469WD-GSRE Clear Lake Solar	74		74
WDT-SR-2556WD-Glendale Drive Solar	2,698	(2,500)	198
R21-DS-2534RD-WCW Selma Generator 1	353	(353)	
WDT-ISP-119626368-Gibson Solar Project	3,131	(70,000)	(66,869)
WDT-ISP-119068517-AlamedaGrantLineSolar1	923	(10,000)	(9,077)
R21-DS-2521RD-WCW Parlier Generator 1	353	(10,000)	(9,647)
MMA-Q1002-Lassen Lodge-ISO50773	329		329
R21-DS-201102-VerweyHanfordPhase2NEMExp	4,317	(10,000)	(5,683)
MMA-Q1378-Gonzaga Wind-ISO53004	2,956		2,956
WDT-FT-119670387-DiscoveryBaySouthClnPwr	3,341	(1,000)	2,341
WDT-FT-119303619-RanchSerenoCleanPower	1,010	(915)	95
MMA-Q877-California Flats Solar-ISO51211	12,903		12,903
MMA-Q1367-WestFordFlatEngyStrg-ISO53078	751	(751)	
WDT-FT-119687649-ApplegateCleanPowerOne		(1,000)	(1,000)
WDT-ISP-119699805-Merced 2	788	(10,000)	(9,212)
WDT-ISP-119712209-Westside Solar Project	729	(10,000)	(9,271)
WDT-FT-119687771-BethellsIslandCleanPwrOne	1,361	(1,000)	361
WDT-FT-119700603-SVUSD Bus Barn	2,127	(1,000)	1,127
R21-DS-2546RD-Engeman SVRC Energy	791	(10,000)	(9,209)
WDT-FT-119687890-Mantova Clean Power	2,019	(1,000)	1,019
MMA-Q1454-Hummingbird-ISO53156	1,415		1,415
WDT-ISP-119763998-Byron PV	2,104	(10,000)	(7,896)
MMA-Q1493-Azalea-ToReduce BESS-ISO53229	1,556		1,556
MMA-Q779-Freeman Wright Solar-ISO50712	6,350		6,350
MMA-Q1391-Sonrisa-AddBattryEngy-ISO53017	5,531		5,531
MMA-Q643X-TranquilityLLC-ISO50647	5,432		5,432
EGI:TO-FS-VistraEnergy-Oakland ES Unit 2	17,406	(15,000)	2,406
WDT-SR-2590WD-RailroadWintersCleanPwr	1,620	(2,500)	(880)
MMA-Q1374-Elkhorn Energy Storage-ISO5308	720		720
MMA-Q1117-Aquamarine-ISO51817	880		880
R21-DS-210197-TomaTek-Microgrid NEMMT	2,420	(50,000)	(47,580)
WDT-FT-119867810-ValleysEdgeCleanPowerA		(1,000)	(1,000)
WDT-ISP-119916059-Alpaugh Dac Solar	810	(10,000)	(9,190)
WDT-ISP-119916650-Jacobs Dac Solar	604	(10,000)	(9,396)
WDT-ISP-119712090-Wellfield Dac Solar	563	(10,000)	(9,437)
WDT-ISP-119916434-Henrietta Dac Solar	646	(10,000)	(9,354)
Q1010-FS-Altamonts wind-Wind Study	12,456		12,456
R21-DS-118714831-NJUHSD_NevadaUnionHS	2,918	(10,000)	(7,082)
WDT-FT-119927046-Foster Clean Power A	877	(2,000)	(1,123)
WDT-FT-119927197-OrovilleDamCleanPower	78		78
R21-DS-210276-Resiliency-DeptOfTheArmy		(10,000)	(10,000)
R21-DS-220326-Amazon DUR3 NEMPS		(10,000)	(10,000)
WDT-ISP-119926766-Riosa Solar	134	(10,000)	(9,866)
WDT-SR-2597WD-Ranch Sereno Clean Power	1,004	(2,500)	(1,496)
MMA-Q539-Frontier Solar 1-ISO60070	480		480
R21-DS-228039-SonomaValleyHospital		(10,000)	(10,000)
MMA-Q1277-Mulqueeney-ISO51994	1,342		1,342
MMA-Q1459-MulqueeneyRanch2Prjts-ISO53184	583		583

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

WDT-SR-2598WD-DiscoveryBaySouthCleanPwr			(2,500)	(2,500)
WDT-FT-119984380-ElDoradoParkCommSolar		537	(1,000)	(463)
WDT-FT-119998837-Dos Palo Clean Power			(1,000)	(1,000)
WDT-SR-2609WD-Mantova Clean Power			(2,500)	(2,500)
WDT-SR-2603WD-BethellsIslandCleanPowerOne			(2,500)	(2,500)
R21-DS-205844-AllanHancockCollege-NEMPS			(10,000)	(10,000)
R21-DS-229642-River Ranch -NEMA		1,980	(10,000)	(8,020)
WDT-SR-2605WD-Applegate Clean Power 1			(2,500)	(2,500)
R21-DS-120090412-LibertyPackingPowerGen			(62,000)	(62,000)
R21-DS-120112145-HighRollerDairyNEMA		1,076	(10,000)	(8,924)
R21-DS232235-BellanaveRanch-SunnyCowNEMA			(10,000)	(10,000)
WDT-SR-2621WD-Oroville Dam Clean Power		67	(2,500)	(2,433)
WDT-FT-120150141-West Tambo Clean Power		126	(1,000)	(874)
R21-DIS-Syntech Bioenergy-Carriere Fam F	(4,091)	4,091		
R21-DS: TONY MEIRINHO DAIRY AND SONS	3,623			3,623
R21-DS: Marysville Joint Unified School	(7,724)	7,724		
R21-DS: County of Kern - Industrial	(8,921)	8,921		
R21-DS: County of Kern - Mt. Vernon	(6,995)	6,995		
Rule21:DSFresnoUnifiedSchoolSunnysideH.S	(7,052)	7,052		
Rule21DS-Re-evaluation-SanJoaquinCounty	(7,373)	7,373		
R21:FS - Abel Road Bioenergy - 1986-RD	(15,000)			(15,000)
Rule21-Detailed Study-FIRESTONEWALKERINC	(7,543)			(7,543)
Rule21-DS-7THSTANDARDRA-SunPacific-Lerdo	(9,186)			(9,186)
Rule21:DS-CALAMCO	(1,226)			(1,226)
Rule21:DS-WAL-MARTSTORES-WAL-MART#1608	(19,293)			(19,293)
R21-FS-TLT Enterprises-HatCreekBioenergy	(15,000)			(15,000)
R21-DS-118550964-Crimson PV		1,402	(10,000)	(8,598)
R21-DIS-Golden State FC-Golden State	(768)	768		
R21-DIS-Crimson Resources-Crimson Resour	(2,936)	2,936		
R21-EIT: SynTech-1627-RD Colusa Ind Park	(2,138)	2,138		
Total Generation	(3,476,259)	2,177,288	(2,276,866)	(3,575,837)

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	PURCHASED GAS BALANCING ACCOUNT	18,272,457	1,723,711,911	400	1,727,476,649	14,507,719
2	Amortization : < 12 MONTHS					
3	BCA CHARGE ACCOUNT	(1,950,179)	2,676,726	400	1,209,312	-482,765
4	Amortization : < 12 MONTHS					
5	CA ALTERNATE RATES FOR ENERGY	76,355,535	668,419,881	400	560,461,952	184,313,464
6	Amortization : < 12 MONTHS					
7	CA ALTERNATE RATES FOR ENERGY PROGRAM-GAS	(21,476,854)	148,126,551	400	123,843,915	2,805,782
8	Amortization : < 12 MONTHS					
9	ELECTRIC HAZARDOUS SUBSTANCE BALANCING	29,500,846	64,862,848	182.3	59,281,930	35,081,764
10	Amortization : < 12 MONTHS					
11	GAS HAZARDOUS SUBSTANCE BALANCING ACCOUNT	68,835,306	151,346,645	182.3	138,324,503	81,857,448
12	Amortization : < 12 MONTHS					
13	CORE FIXED COST GAS BALANCING ACCOUNT	303,612,079	2,735,115,108	400	2,936,678,573	102,048,614
14	Amortization : < 12 MONTHS					
15	TRANSITION COST - NONCORE BALANCING ACCOUNT	(34,665,239)	186,761,037	400	149,459,286	2,636,512
16	Amortization : < 12 MONTHS					
17	CORE PIPELINE DEMAND CHARGE ACCOUNT	9,971,676	618,082,856	400	634,286,509	-6,231,977
18	Amortization : < 12 MONTHS					
19	CEE INCENTIVE ELECTRIC BALANCING ACCOUNT	8,772,763	16,788,756	400	15,396,640	10,164,879
20	Amortization : < 12 MONTHS					
21	CEE INCENTIVE GAS BALANCING ACCOUNT	2,933,420	5,176,519	400	2,768,505	5,341,434
22	Amortization : < 12 MONTHS					
23	GAS CORE FIRM STORAGE ACCOUNT	3,859,012	245,920,799	400	247,852,893	1,926,918
24	Amortization : < 12 MONTHS					
25	ENERGY RESOURCE RECOVERY ACCOUNT	(616,011,174)	3,778,881,654	400	3,253,378,314	-90,507,834
26	Amortization : < 12 MONTHS					
27	ENERGY RECOVERY BONDS BALANCING ACCOUNT	3,668,687	23,861,324	400	2,421,026	25,108,985
28	Amortization : < 12 MONTHS					
29	ELECTRIC PRICE RISK MANAGEMENT - CURRENT	23,546,613	190,584,721	555	178,882,909	35,248,425
30	Amortization : NO STATED					
31	ENVIRONMENTAL COMPLIANCE NON-HSM	34,959,214	4,767,732	228.4	5,762,976	33,963,970
32	Amortization : 32 YEARS					
33	ENVIRONMENTAL COMPLIANCE	233,466,150	48,538,971	182.3	38,204,729	243,800,392
34	Amortization : 32 YEARS					
35	DISTRIBUTION REVENUE ADJUSTMENT MECHANISM	(30,778,807)	5,773,314,506	400	5,797,213,702	-54,678,003
36	Amortization : < 12 MONTHS					
37	DEFERRED DEBIT - GAS RESERVES (CONTRA BALANCING	(526,402,269)	417,977,874	400	437,566,333	-545,990,728
38	Amortization : < 12 MONTHS					
39	TRANSMISSION REVENUE BALANCING ACCOUNT	(68,843,767)	237,329,237	400	212,690,752	-44,205,282
40	Amortization : < 12 MONTHS					
41	RELIABILITY SERVICES BALANCING ACCOUNT	(49,216,013)	44,576,123	400	1,747,543	-6,387,433
42	Amortization : < 12 MONTHS					
43	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)	1,845,579,252	400	999,999,999	-154,420,746
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)				-999,999,999
2	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)				-999,999,999
3	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(999,999,999)				-999,999,999
4	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT	(321,727,179)				-321,727,179
5	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
6	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
7	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
8	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
9	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
10	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
11	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
12	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
13	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
14	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
15	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
16	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
17	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
18	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
19	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
20	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
21	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
22	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
23	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
24	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
25	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
26	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				999,999,999	-999,999,999
27	ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT				842,395,313	-842,395,313
28	Amortization : < 12 MONTHS					
29	GAS PRICE RISK MANAGEMENT - CURRENT	1,597,867	15,445,208	807	14,676,096	2,366,979
30	Amortization : NO STATED					
31	TRANSMISSION ACCESS CHARGE BALANCING ACCOUNT	9,137,882	258,277,253	400	483,166,010	-215,750,875
32	Amortization : < 12 MONTHS					
33	DWR POWER CHARGE COLLECTION BALANCING	(974,054)	2,862,587	400	4,632,049	-2,743,516
34	Amortization : < 12 MONTHS					
35	PUBLIC PURPOSE PROGRAMS REVENUE ADJUSTMENT	(21,934,721)	216,949,419	400	233,040,258	-38,025,560
36	Amortization : < 12 MONTHS					
37	MODIFIED TRANSITION COST BALANCING ACCOUNT	(6,588,896)	136,013,695	400	177,225,941	-47,801,142
38	Amortization : < 12 MONTHS					
39	END-USE CUSTOMER REFUND ADJUSTMENT	(762,802)	180,210	400	249,553	-832,145
40	Amortization : < 12 MONTHS					
41	CATASTROPHIC EVENT MEMORANDUM ACCOUNT	828,589,615	426,336,798	182.3	677,113,367	577,813,046
42	Amortization : < 12 MONTHS					
43	GAS PUBLIC PURPOSE PROGRAM SURCHARGE MEMO	43,486,118	208,957,981	186	219,859,814	32,584,285
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Amortization : < 12 MONTHS					
2	PROCUREMENT ENERGY EFFICIENCY REV. ADJ.	(124,810,083)	107,638,035	400	32,545,734	-49,717,782
3	Amortization : < 12 MONTHS					
4	FAMILY ELECTRIC RATE ASSISTANCE BALANCING ACCT	6,968,547	11,579,252	400	6,968,601	11,579,198
5	Amortization : < 12 MONTHS					
6	NEGATIVE ONGOING COMPETITION TRANSITION CHRGR BA	999,999,999	43,671,642	182.3	11,735,775	1,031,935,866
7	NEGATIVE ONGOING COMPETITION TRANSITION CHRGR BA	999,999,999				999,999,999
8	NEGATIVE ONGOING COMPETITION TRANSITION CHRGR BA	999,999,999				999,999,999
9	NEGATIVE ONGOING COMPETITION TRANSITION CHRGR BA	257,964,695				257,964,695
10	Amortization : < 12 MONTHS					
11	LAND CONSERV. PLAN ENV. REMEDIATION MEMO ACCT.	2,112,733	963,935	182.3	2,112,733	963,935
12	Amortization : < 12 MONTHS					
13	CA SOLAR INITIATIVE THERMAL PROGRAM MEMO	9,003,658	11,750,423	400	7,038,711	13,715,370
14	Amortization : < 12 MONTHS					
15	DIABLO CANYON SEISMIC STUDIES BALANCING ACCT	8,581,524	7,249,912	182.3	11,834,549	3,996,887
16	Amortization : < 12 MONTHS					
17	Wildfire Expense Memorandum Account - Gas	12,070,022	23,388,047	400	29,799,056	5,659,013
18	Amortization : > 12 MONTHS					
19	Wildfire Expense Memorandum Account - Electric	14,575,884	43,556,311	400	43,641,982	14,490,213
20	Amortization : > 12 MONTHS					
21	GAS HAZARDOUS SUBSTANCE REGULATORY ASSET	544,754,349	113,257,598	182.3	89,144,367	568,867,580
22	Amortization : 32 YEARS					
23	GAS NON-HAZARDOUS SUBSTANCE REGULATORY ASSET	132,103,733	11,028,806	228.4	6,493,425	136,639,114
24	Amortization : 32 YEARS					
25	NON CURRENT HSM BA ELEC	35,119,163	76,756,297	182.3	73,323,891	38,551,569
26	Amortization : > 12 MONTHS					
27	NON CURRENT HSM BA GAS	81,944,713	179,098,027	182.3	171,089,080	89,953,660
28	Amortization : > 12 MONTHS					
29	FIRE HAZARD PREVENTION MEMO ACCT	304,113,159	4,332,966	182.3	125,769,286	182,676,839
30	Amortization : < 12 MONTHS					
31	ELECTRIC PRICE RISK MANAGEMENT - NONCURRENT	124,040,367	1,140,498,438	555	1,060,576,766	203,962,039
32	Amortization : NO STATED					
33	FASB 109 REGULATORY ASSET	252,210,442	999,999,999	282	73,592,191	1,178,618,250
34	FASB 109 REGULATORY ASSET		999,999,999			999,999,999
35	FASB 109 REGULATORY ASSET		999,999,999			999,999,999
36	FASB 109 REGULATORY ASSET		999,999,999			999,999,999
37	FASB 109 REGULATORY ASSET		999,999,999			999,999,999
38	FASB 109 REGULATORY ASSET		999,999,999			999,999,999
39	FASB 109 REGULATORY ASSET		554,657,560			554,657,560
40	Amortization : 1-45 YEARS					
41	GAS TRANSMISSION AND STORAGE REVENUE SHARING	(44,734,459)	493,791,913	400	524,951,965	-75,894,511
42	Amortization : < 12 MONTHS					
43	NUCLEAR DECOMMISSIONING ADJUSTMENT MECHANISM	12,746,703	77,448,241	400	87,128,406	3,066,538
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Amortization : 2 YEARS					
2	DEPARTMENT OF ENERGY LITIGATION BALANCING	(25,354,080)	25,361,631	182.3	18,614,816	-18,607,265
3	Amortization : > 12 MONTHS					
4	DEMAND RESPONSE EXPENDITURES BALANCING	(11,113,430)	38,989,423	400	40,291,765	-12,415,772
5	Amortization : < 12 MONTHS					
6	AMCDOP-COST ADJUST MECHANISM-OTHER	(61,088,566)	178,310,188	400	50,829,537	66,392,085
7	Amortization : <12 MONTHS					
8	NEW SYSTEM GENERATION BA	186,518,704	287,783,377	400	383,668,940	90,633,141
9	Amortization : < 12 MONTHS					
10	ELECTRIC PROGRAM INVESTMENT CHARGE	4,097,405	93,781,927	400	92,049,844	5,829,488
11	Amortization : < 12 MONTHS					
12	GREENHOUSE GAS EXPENSE MEMO ACCOUNT	(612,014)	597,627	400	1,213,678	-1,228,065
13	Amortization : NO STATED					
14	GAS PROGRAM BALANCING ACCOUNT	3,801,248	164,571,388	400	166,959,998	1,412,638
15	Amortization : < 12 MONTHS					
16	GREENHOUSE GAS EXPENSE MEMORANDUM ACCOUNT -	1,124,703	227,448	400	1,126,011	226,140
17	Amortization : < 12 MONTHS					
18	GREEN TARIFF SHARED RENEWABLES MEMORANDUM	6,796,509	1,499,533	400	636,814	7,659,228
19	Amortization : < 12 MONTHS					
20	GPBA - GHG OPERATIONAL COSTS SUBACCOUNT	(11,886,564)	12,543,630	400	25,968,018	-25,310,952
21	Amortization : <12 MONTHS					
22	GREEN TARIFF SHARED RENEWABLES BALANCING	276,572	11,636,946	400	11,671,177	242,341
23	Amortization : <12 MONTHS					
24	AVOIDED COST CALC UPDATE MEMO ACCOUNT	4,533	277,691	400	6,283	275,941
25	Amortization : <12 MONTHS					
26	DISTRIBUTED RESOURCES PLAN MEMORANDUM ACCT	2,515,273	3,342,481	400		5,857,754
27	Amortization : > 12 MONTHS					
28	DEMAND RESPONSE EXPENDITURES BA - DRAM	(10,606,980)	4,910,818	400	6,498,297	-12,194,459
29	Amortization : > 12 MONTHS					
30	NONCURR WILDFIRE EXP MEMO ACCT - GAS	183,443,967	25,450,095	182.3	31,049,939	177,844,123
31	Amortization : > 12 MONTHS					
32	NONCURR WILDFIRE EXP MEMO ACCT - ELEC	349,536,095	999,999,999	182.3	65,737,148	1,283,798,946
33	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
34	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
35	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
36	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
37	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
38	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
39	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
40	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
41	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
42	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
43	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
2	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
3	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
4	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
5	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
6	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
7	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
8	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		999,999,999			999,999,999
9	NONCURR WILDFIRE EXP MEMO ACCT - ELEC		834,054,078			834,054,078
10	Amortization : > 12 MONTHS					
11	BA - PORTFOLIO ALLOCATION BAL ACCOUNT	752,011,872	5,974,886,219	400	6,535,592,306	191,305,785
12	Amortization : <12 MONTHS					
13	NRCRBA - CURRENT	11,154,006	67,539,251	182.3	77,961,404	731,853
14	Amortization : <12 MONTHS					
15	FIRE RISK MITIGATION MEMO ACCT	107,949,689	199,777,759	400	227,759,038	79,968,410
16	Amortization : <12 MONTHS					
17	CALI CONSUMER PRIVACY ACT MEMO ACCT-ELEC	6,390,884	7,755,743	182.3	2,586	14,144,041
18	Amortization : > 12 MONTHS					
19	CALI CONSUMER PRIVACY ACT MEMO ACCT-GAS	5,228,905	6,345,608	182.3	2,117	11,572,396
20	Amortization : > 12 MONTHS					
21	Gas Storage Balancing Account		15,774,898	182.3	22,551,347	-6,776,449
22	Amortization : > 12 MONTHS					
23	Measurement and Control Ovr-Pressure Prot		4,448,721	182.3	1,405,806	3,042,915
24	Amortization : > 12 MONTHS					
25	In-Line Inspection mem account		112,874,064	182.3	44,997,795	67,876,269
26	Amortization : > 12 MONTHS					
27	Gas Statues Rules Reg Memo Acct		2,717,290	400	1,652,384	1,064,906
28	Amortization : > 12 MONTHS					
29	Internal Corrosion Direct Assessment Memo Acct		16,831,994	400	7,784,160	9,047,834
30	Amortization : > 12 MONTHS					
31	Integrated Resource Planning Cost Memorandum Account		1,004,332	400		1,004,332
32	Amortization : < 12 months					
33	General Rate Case Memorandum Account - Electric - t		277,299,275	400		277,299,275
34	Amortization : < 12 months					
35	General Rate Case Memorandum Account - Electric - t		7,091,052,840	400	6,758,293,703	332,759,137
36	Amortization : > 12 months					
37	General Rate Case Memorandum Account - Gas - Curret		35,792,522	400		35,792,522
38	Amortization : < 12 months					
39	General Rate Case Memorandum Account - Gas - NonCut		1,982,869,072	400	1,939,918,045	42,951,027
40	Amortization : > 12 months					
41	Wildfire Mitigation Bal Acct - Electric Curr		326,721,952	400	300,144,152	26,577,800
42	Amortization : < 12 months					
43	Microgrid Memorandum Account		224,409,111	400	91,349,226	133,059,885
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

OTHER REGULATORY ASSETS (Account 182.3)

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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.
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				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Amortization : < 12 months					
2	LINE 407 MEMO ACCT NC	7,003,180	1,621,801	182.3	3,541,469	5,083,512
3	Amortization : >12 MONTHS					
4	CRITICAL DOCS PROGRAM MEMO ACCT NC	12,220,156	8,301,726	182.3	8,307,822	12,214,060
5	Amortization : >12 MONTHS					
6	TRANSMISSION INTEGRITY MGMT BAL ACCT	106,743,862	24,785,348	182.3	149,568,715	-18,039,505
7	Amortization : >12 MONTHS					
8	TRANSMISSION INTEGRITY MGMT MEMO ACCT		483,765	182.3		483,765
9	Amortization : >12 MONTHS					
10	INTEGRATED DISTRIBUTION ENERGY RESOURCES	462,656	575,002	400	545,744	491,914
11	Amortization : > 12 MONTHS					
12	CATASTROPHIC EVENT MEMORANDUM ACCOUNT - GAS	1,901,407	16,220,279	400	2,009,337	16,112,349
13	Amortization : < 12 MONTHS					
14	MISC ELEC-CURRENT-FERC INTEREST BEARING	60,490,225	2,518,654	400	53,833	62,955,046
15	Amortization : <12 MONTHS					
16	TREE MORTALITY NON-BYPASSABLE CHARGE BAL ACCT	62,641,697	78,162,205	400	109,432,379	31,371,523
17	Amortization : <12 MONTHS					
18	Wildfire Mitigation Plan Memo Acct	532,196,134	1,194,685,872	182.3	1,351,522,508	375,359,498
19	Amortization : <12 MONTHS					
20	MISCELLANEOUS GAS REG ASSET - CURRENT	12,037,758	147,958,843	VARIOUS	89,545,865	70,450,736
21	Amortization : < 12 MONTHS					
22	MISCELLANEOUS ELECTRIC REG ASSET - CURRENT	70,632,093	293,221,391	VARIOUS	138,744,323	225,109,161
23	Amortization : < 12 MONTHS					
24	ACCUM AMORT - URG PLANT REG ASSET	3,520,575		405		3,520,575
25	Amortization : < 12 MONTHS					
26	MOBILE HOME PARK BA ELECTRIC NC	28,908,987	4,356,939	597	5,913,034	27,352,892
27	Amortization : > 12 MONTHS					
28	MOBILE HOME PARK BA GAS NC	27,669,761	3,262,914	893	4,578,353	26,354,322
29	Amortization : > 12 MONTHS					
30	MOBILE HOME PARK BA ELECTRIC CURRENT	3,339,022	4,219,772	597	3,860,583	3,698,211
31	Amortization : < 12 MONTHS					
32	MOBILE HOME PARK BA GAS CURRENT	3,586,641	4,578,353	893	4,177,735	3,987,259
33	Amortization : < 12 MONTHS					
34	REG ASSET - MISCELLANEOUS GAS - NON-CURRENT	142,698,840	2,281,383,272	400	1,999,856,763	424,225,349
35	Amortization : > 12 MONTHS					
36	MISCELLANEOUS ELECTRIC REG ASSET - NONCURRENT	326,697,074	2,515,321,823	549	2,063,466,978	778,551,919
37	Amortization : 25 YEARS					
38	REG ASSET - ABANDONED CAPITAL PROJECTS	34,688,762	3,493,889	400	32,087,211	6,095,440
39	Amortization : < 12 MONTHS					
40	REGULATORY ASSET-CEMA-ELEC-NONCURRENT	699,146,194	1,104,739,532	588	877,156,530	926,729,196
41	Amortization : > 12 MONTHS					
42	CEMA GAS NONCURRENT	45,682,327	106,423,165	400	121,016,764	31,088,728
43	Amortization : > 12 MONTHS					
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

OTHER REGULATORY ASSETS (Account 182.3)

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1	Regulatory Asset-CEMA-Other-NonCurrent		24,395,003	880	1,021,555	23,373,448
2	Amortization : > 12 MONTHS					
3	MOBILE HOME PARK BALANCING ACCOUNT - ELECTRIC	24,546,831	37,830,788	182.3	40,834,202	21,543,417
4	Amortization : <12 MONTHS					
5	Regulatory Asset-DCPP M&S Inventory Non Current		60,300,000	400	24,120,000	36,180,000
6	Amortization : > 12 months					
7	Regulatory Asset-DCPP M&S Inventory Current		12,060,000	182.3		12,060,000
8	Amortization : > 12 months					
9	MOBILE HOME PARK BALANCING ACCOUNT - GAS	24,460,775	38,361,450	182.3	40,942,290	21,879,935
10	Amortization : <12 MONTHS					
11	WILDFIRES CUSTOMER PROTECTIONS MEMO ACCT - E	4,101,006	2,016,246	400	105,147	6,012,105
12	Amortization : > 12 MONTHS					
13	WILDFIRES CUSTOMER PROTECTIONS MEMO ACCT - G	3,355,370	1,649,653	400	86,030	4,918,993
14	Amortization : > 12 MONTHS					
15	Fire Hazard Prevention Memo Acct		303,854,403	400		303,854,403
16	Amortization : < 12 MONTHS					
17	Fire Risk & Wildfire Mitigation Memo Acct		738,818,793	400	62,508,380	676,310,413
18	Amortization : < 12 MONTHS					
19	Risk Transfer Bal Acct - Electric Curr		304,228,800	400	123,810,907	180,417,893
20	Amortization : < 12 months					
21	Risk Transfer Bal Acct - Electric Curr		107,157,524	400	43,609,514	63,548,010
22	Amortization : < 12 months					
23	Risk Transfer Bal Acct - Electric Curr		137,085,486	400	49,996,666	87,088,820
24	Amortization : < 12 months					
25	Risk Transfer Bal Acct - Electric Curr		48,285,176	400	17,610,164	30,675,012
26	Amortization : < 12 months					
27	BioMAT Non-Bypassable Charge		1,616,264	400	531,065	1,085,199
28	Amortization : < 12 months					
29	COVID-19 Pandemic Protection Memorandum Account -		169,964,216	400	108,895,814	61,068,402
30	Amortization : > 12 MONTHS					
31	COVID-19 Pandemic Protection Memo Account -Gas -NC		54,203,623	400	31,102,321	23,101,302
32	Amortization : > 12 MONTHS					
33	FINANCING COSTS REGULATORY ASSET	166,026,930	35,359,547	428	19,796,642	181,589,835
34	Amortization : 20 YEARS					
35	URG PLANT REGULATORY ASSET - NONCURRENT	944,805,000		407.4		944,805,000
36	Amortization : 22 YEARS					
37	URG PLANT REGULATORY ASSET - TAX	183,010,953		182.3		183,010,953
38	Amortization : 11 YEARS					
39	ACCUM AMORT - URG PLANT REG ASSET NON CURRENT	(730,975,723)		405	43,352,004	-774,327,727
40	Amortization : 12 YEARS					
41	ACC AMT - PLANT RA TAX	(168,928,625)		405	3,520,572	-172,449,197
42	Amortization : 11 YEARS					
43	UNAMORTIZED FINANCIAL HEDGING COST	11,107,455		428	836,195	10,271,260
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

OTHER REGULATORY ASSETS (Account 182.3)

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				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Amortization : 20 YEARS					
2	PENSION REGULATORY ASSET	999,999,999	557,556,818	926	136,054,740	1,421,502,077
3	PENSION REGULATORY ASSET	823,127,653				823,127,653
4	Amortization : INDEFINITE					
5	URG PLANT REGULATORY ASSET - CURRENT	42,239,000		407.4		42,239,000
6	Amortization : < 12 MONTHS					
7	MAJOR EMERGENCY BALANCING ACCOUNT	60,259,604	288,264,925	182.3	349,142,965	-618,436
8	Amortization : <12 MONTHS					
9	FIN 47 - REGULATORY ASSET	17,969,734	21,106,849	101	1,460,578	37,616,005
10	Amortization : NO STATED					
11	RESIDENTIAL RATE REFORM MEMORANDUM ACCOUNT	13,174,261	35,422,635	182.3	67,233,766	-18,636,870
12	Amortization : <12 MONTHS					
13	REGULATORY ASSET - HYRDO NONCURRENT	11,058,629	180,994	400	65,094	11,174,529
14	Amortization : > 12 MONTHS					
15	FINANCING COSTS - CURRENT	18,503,848	1,951,319	428	1,803,752	18,651,415
16	Amortization : < 12 MONTHS					
17	UNAMORTIZED FINANCIAL HEDGING COST CURRENT	836,195		428		836,195
18	Amortization : < 12 MONTHS					
19	NEW ENVIRONMENTAL REGULATIONS BALANCING	20,049,085	16,247,215	400	41,416,841	-5,120,541
20	Amortization : > 12 MONTHS					
21	DIABLO CANYON RETIREMENT BAL ACCT (DEPR) -		12,060,000	400	37,947,818	-25,887,818
22	Amortization : > 12 MONTHS					
23	DCRBA - DCPPE EMPLOYEE RETENTION PROGRAM	54,765,700	52,557,622	400	50,660,811	56,662,511
24	Amortization : > 12 MONTHS					
25	San Joaq. Valley Disadv. Comm. Pilot BA	(2,972,911)	1,481,442	400	8,956,114	-10,447,583
26	Amortization : < 12 MONTHS					
27	Disadv Comm Single Family Solar Homes Memo Acct	3,890,985	10,134,804	400	9,559,941	4,465,848
28	Amortization : < 12 MONTHS					
29	Disadv Comm Green Tariff Program Bal Acct		3,151,801	400	13,532,361	-10,380,560
30	Amortization : < 12 MONTHS					
31	Net Energy Metering Balancing Account		646,632	400	242,543	404,089
32	Amortization : > 12 MONTHS					
33	Community Solar Green Tariff Balance Account		1,082,461	182.3	6,127,178	-5,044,717
34	Amortization : < 12 MONTHS					
35	PCIA Undercollection Balancing Account		244,540,761	400	163,027,191	81,513,570
36	Amortization : < 12 MONTHS					
37	Disconnections Memorandum Account - Gas NC		299,576	400		299,576
38	Amortization : > 12 MONTHS					
39	Disconnections Memorandum Account - Electric NC		366,148	400		366,148
40	Amortization : > 12 MONTHS					
41	WMBA - Electric Reason Review (Non-Curr)		170,658,135	501	14,889,816	155,768,319
42	Amortization : > 12 MONTHS					
43	Vegetation Management Balancing Acct (VMBA) - Curr		845,355,716	400	730,743,522	114,612,194
44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Amortization : < 12 MONTHS					
2	Vegetation Management Balancing Acct (VMBA) - NC		730,743,522	501	138,266,487	592,477,035
3	Amortization : < 12 MONTHS					
4	Adj Mechanism for Costs in Other Proceedings - NC		19,200,207	515	4,282,564	14,917,643
5	Amortization : < 12 MONTHS					
6	Miscellaneous minor items	192,374,544	1,741,643,100	VARIOUS	1,933,793,428	224,216
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44	TOTAL	7,027,240,817	81,757,684,690		72,728,023,105	16,056,902,402

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 43 Column: b

The FERC software will not allow the entire ending balance of ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT of (\$4,321,727,175) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 43: (999,999,999)
Line 1: (999,999,999)
Line 2: (999,999,999)
Line 3: (999,999,999)
Line 4: (321,727,179)
Total (4,321,727,175)

Schedule Page: 232 Line No.: 43 Column: f

The FERC software will not allow the entire ending balance of ELECTRIC BALANCING ACCOUNT RESERVE ACCOUNT of (\$26,318,543,213) to be shown, as it is too large. As such, the balance has been broken into the following:

Line 43: (154,420,746)
Line 1: (999,999,999)
Line 2: (999,999,999)
Line 3: (999,999,999)
Line 4: (321,727,179)
Line 5: (999,999,999)
Line 6: (999,999,999)
Line 7: (999,999,999)
Line 8: (999,999,999)
Line 9: (999,999,999)
Line 10: (999,999,999)
Line 11: (999,999,999)
Line 12: (999,999,999)
Line 13: (999,999,999)
Line 14: (999,999,999)
Line 15: (999,999,999)
Line 16: (999,999,999)
Line 17: (999,999,999)
Line 18: (999,999,999)
Line 19: (999,999,999)
Line 20: (999,999,999)
Line 21: (999,999,999)
Line 22: (999,999,999)
Line 23: (999,999,999)
Line 24: (999,999,999)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Line 25:	(999,999,999)
Line 26:	(999,999,999)
Line 27:	(842,395,313)
Total	<u>(26,318,543,213)</u>

Schedule Page: 232.2 Line No.: 6 Column: b

The FERC software will not allow the entire ending balance of NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA of \$3,257,964,692 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 6:	999,999,999
Line 7:	999,999,999
Line 8:	999,999,999
Line 9:	257,964,695
Total	<u>3,257,964,692</u>

Schedule Page: 232.2 Line No.: 6 Column: f

The FERC software will not allow the entire ending balance of NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA of \$3,289,900,559 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 6:	1,031,935,866
Line 7:	999,999,999
Line 8:	999,999,999
Line 9:	289,900,562
Total	<u>3,289,900,559</u>

Schedule Page: 232.2 Line No.: 33 Column: f

The FERC software will not allow the entire ending balance of FASB 109 REGULATORY ASSET of \$6,733,275,805 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 33:	1,178,618,250
Line 34:	999,999,999
Line 35:	999,999,999
Line 36:	999,999,999
Line 37:	999,999,999
Line 38:	999,999,999
Line 39:	554,657,560
Total	<u>6,733,275,805</u>

Schedule Page: 232.3 Line No.: 32 Column: f

The FERC software will not allow the entire ending balance of NONCURR WILDFIRE EXP MEMO ACCT - ELEC of \$21,117,853,005 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 32:	1,283,798,946
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Line 33:	999,999,999
Line 34:	999,999,999
Line 35:	999,999,999
Line 36:	999,999,999
Line 37:	999,999,999
Line 38:	999,999,999
Line 39:	999,999,999
Line 40:	999,999,999
Line 41:	999,999,999
Line 42:	999,999,999
Line 43:	999,999,999
Line 1:	999,999,999
Line 2:	999,999,999
Line 3:	999,999,999
Line 4:	999,999,999
Line 5:	999,999,999
Line 6:	999,999,999
Line 7:	999,999,999
Line 8:	999,999,999
Line 9:	834,054,078

Total 21,117,853,005

Schedule Page: 232.5 Line No.: 20 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets and 254 - Other Regulatory Liabilities

Schedule Page: 232.5 Line No.: 22 Column: d

Primarily internal labor expenses. Offset to 182.3 - Other Regulatory Assets, 549 - Misc. Other Power Generation Expenses and 253 - Other Deferred Credits.

Schedule Page: 232.7 Line No.: 2 Column: b

The FERC software will not allow the entire ending balance of PENSION REGULATORY ASSET of \$1,823,127,652 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 2: 999,999,999

Line 3: 823,127,653

Total 1,823,127,652

Schedule Page: 232.7 Line No.: 2 Column: f

The FERC software will not allow the entire ending balance of PENSION REGULATORY ASSET of \$2,244,629,730 to be shown, as it is too large. As such, the balance has been broken into the following:

Line 2: 1,421,502,077

Line 3: 823,127,653

Total 2,244,629,730

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 232.8 Line No.: 6 Column: d

Activity primarily related to CORE BROKERAGE FEE, RENEWABLES PORTFOLIO STANDARD COST MEMO ACCT, LAND CONSERVATION PLAN IMPLEMENTATION MEMO, GAS PRICE RISK MANAGEMENT - NONCURRENT, HLBA - CURRENT, Disadv Comm Single Family Solar Homes Memo Acct, Wildfire Mitigation Bal Acct - Gas Curr, DAILY BIOMETHANE SOLICITATION MEMO ACCT-NONCURRENT with offsets to 182.3, 400 and 807.

MISCELLANEOUS DEFERRED 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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Undistributed Charges	-13,361,757	1,304,545,078	VARIOUS	1,319,610,470	-28,427,149
2	Customer Advance for Constructn	7,475,301	529,988	VARIOUS	554,603	7,450,686
3	Development Costs	50,267,431	31,856,378	131	48,731,815	33,391,994
4	Payments for MLX					
5	and Non-Energy Invoices	1,266,847	838,553,193	VARIOUS	839,156,520	663,520
6	Payments for Main Line					
7	Extension	-2,763,355	151,549,821	VARIOUS	152,042,695	-3,256,229
8	Clearing Account for					
9	JP Morgan Chase	1,147,639	9,221,355	VARIOUS	10,020,310	348,684
10	Payroll Clearing Account	886,787	14,401,331,980	VARIOUS	14,402,411,521	-192,754
11	Land Surplus	1,394,328	399,255	930.2	559,462	1,234,121
12	Reimb Transm Svc, Gen Intercons	-1,142,705	8,401,372	VARIOUS	7,432,678	-174,011
13	Miscellaneous minor items	25,969	116,885,351	VARIOUS	111,577,776	5,333,544
14	Wildfire Fund - NonCurr Assets		6,047,877,976	186	232,119,758	5,815,758,218
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,196,485				5,832,130,624

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 1 Column: d

Typical Accounts charged: 131, 142

Schedule Page: 233 Line No.: 2 Column: d

Typical Accounts charged: 456, 495

Schedule Page: 233 Line No.: 5 Column: d

Typical Accounts charged: 131, 143

Schedule Page: 233 Line No.: 7 Column: d

Typical Accounts charged: 131, 252

Schedule Page: 233 Line No.: 9 Column: d

Typical Accounts charged: 131, 143, 559

Schedule Page: 233 Line No.: 10 Column: d

Typical Accounts charged: 131

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

Typical Accounts charged: 131, 143

Schedule Page: 233 Line No.: 13 Column: d

Typical Accounts charged 182.3 and 236

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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Environmental	-43,418,496	-43,933,700
3	Compensation	4,278,296	35,955,459
4	CIAC	-119,148,840	-116,370,208
5	Injuries and Damages	6,565,630,896	470,135,340
6	CCFT	91,994,688	-350,949,450
7	Other	946,255,053	7,024,504,298
8	TOTAL Electric (Enter Total of lines 2 thru 7)	7,445,591,597	7,019,341,739
9	Gas		
10	Environmental	-115,579,841	-136,652,000
11	Compensation	28,120,772	36,967,438
12	CIAC	168,789,262	169,477,749
13	Injuries and Damages	-41,616,258	-42,370,119
14	CCFT	-24,398,939	-22,303,313
15	Other	1,251,190,776	1,282,950,101
16	TOTAL Gas (Enter Total of lines 10 thru 15)	1,266,505,772	1,288,069,856
17	Other (Specify)	791,628,533	1,011,575,048
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	9,503,725,902	9,318,986,643

Notes

Electric Other - Line 7	Balance at Beginning of the year	Balance at end of the year
Vacation Paid	19,679,208	28,675,072
Severance Costs		11,452,351
Medical and Group and Life Insurance		(35,507,347)
Short Term Incentive Plan		232,958
Net Operating Loss	(498,617,637)	6,055,672,829
Property Tax	15,958,875	(43,659,350)
Other	1,409,234,607	1,007,637,785
Subtotal	946,255,053	7,024,504,298
Gas Other - Line 15		
Vacation Paid	8,123,444	11,978,813
Severance Costs		5,132,283
Medical and Group Life Insurance		(13,209,905)
Short Term Incentive Plan		(323,736)
Net Operating Loss	862,880,446	1,001,134,629
Property Tax	7,749,033	(15,703,703)
Other	372,437,853	293,941,720
Subtotal	1,251,190,776	1,282,950,101
Other - Line 17		
CCFT	(33,432,595)	(19,340,059)
Compensation	2,302,576	2,302,576
Net Operating Loss	887,460,536	891,068,935
Property Tax	(78,809,974)	391,945
Other	14,107,990	137,151,651
Subtotal	791,628,533	1,011,575,048

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	Pacific Gas and Electric Company's stock			
2	is wholly owned by PG&E Corporation			
3	Common	800,000,000	5.00	
4				
5	TOTAL COMMON	800,000,000		
6				
7	Registered with the American Stock Exchange			
8	Preferred, Cumulative			
9	Redeemable: Without Mandatory Redemption			
10	4.36%	418,291	25.00	25.75
11	4.50%	611,142	25.00	26.00
12	4.80%	793,031	25.00	27.25
13	5.00%	1,778,172	25.00	26.75
14	5.00% - Series A	934,322	25.00	26.75
15	7.04%	3,000,000	25.00	
16	Undesignated in Class	56,180,217		
17				
18	SubTotal Redeemable Without	63,715,175		
19	Mandatory Redemption			
20				
21	Registered with the American Stock Exchange			
22	Non-Redeemable			
23	5.00%	400,000	25.00	
24	5.50%	1,173,163	25.00	
25	6.00%	4,211,662	25.00	
26				
27	SubTotal Non-Redeemable	5,784,825		
28				
29	Redeemable: With Mandatory Redemption			
30	6.30%	2,500,000	25.00	
31	6.57%	3,000,000	25.00	
32	Undesignated in Class	10,000,000	100.00	
33				
34	SubTotal Redeemable With	15,500,000		
35	Mandatory Redemption			
36				
37	TOTAL PREFERRED	85,000,000		
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
264,374,809	1,321,874,045					3
						4
264,374,809	1,321,874,045					5
						6
						7
						8
						9
418,291	10,457,275					10
611,142	15,278,550					11
793,031	19,825,775					12
1,778,172	44,454,300					13
934,322	23,358,050					14
						15
						16
						17
4,534,958	113,373,950					18
						19
						20
						21
						22
400,000	10,000,000					23
1,173,163	29,329,075					24
4,211,662	105,291,550					25
						26
5,784,825	144,620,625					27
						28
						29
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10,319,783	257,994,575					37
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						42

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 250 Line No.: 15 Column: a

Redeemed on August 31, 2005.

Schedule Page: 250 Line No.: 30 Column: a

This was reclassified to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

Schedule Page: 250 Line No.: 31 Column: a

This was reclassified to Other Long-Term Debt in accordance with ASC 480 in September 2003. It was shown here since it is still part of the total number of preferred shares authorized. They were fully redeemed on May 31, 2005.

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	
2	Equity Infusions from Parent Company	26,465,619,786
3	Excess Tax Benefit on Stock Based Compensation	50,960,304
4		
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40	TOTAL	26,516,580,090

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	25,143,083
2		
3	PREFERRED, CUMULATIVE:	
4	Redeemable - \$25 par value per share:	
5	4.36%	29,509
6	4.50%	387,663
7	4.80%	777,999
8	5.00%	1,758,375
9	5.00% - Series A	158,204
10		
11	Non-Redeemable - \$25 par value per share:	
12	5.00%	73,717
13	5.50%	173,730
14	6.00%	449,606
15		
16		
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21		
22	TOTAL	28,951,886

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	Senior Notes 3.50% due 2020 (A)	550,000,000	4,205,770
2			2,728,000 D
3	Senior Notes 3.50% due 2020 (A)	250,000,000	1,897,267
4			6,840,000 D
5	Senior Notes 4.25% due 2021 (A)	300,000,000	2,270,404
6			243,000 D
7	Senior Notes 3.25% due 2021 (A)	250,000,000	1,981,515
8			1,312,500 D
9	Senior Notes 2.45% due 2022 (A)	400,000,000	3,251,743
10			1,164,000 D
11	Senior Notes 3.25% due 2023 (B)	375,000,000	2,924,964
12			1,901,250 D
13	Senior Notes 4.25% due 2023 (B)	500,000,000	4,061,237
14			1,175,000 D
15	Senior Notes 3.85% due 2023 (B)	300,000,000	2,505,170
16			543,000 D
17	Senior Notes 3.75% due 2024 (B)	450,000,000	3,672,801
18			445,500 D
19	Senior Notes 3.40% due 2024 (B)	350,000,000	2,788,492
20			262,500 D
21	Senior Notes 3.50% due 2025 (B)	400,000,000	3,471,059
22			2,540,000 D
23	Senior Notes 3.50% due 2025 (B)	200,000,000	1,716,157
24			-2,716,000 P
25	Senior Notes 3.45% due 2025 (C)	875,000,000	3,645,283
26	Senior Notes 2.95% due 2026 (B)	600,000,000	5,241,785
27			1,596,000 D
28	Senior Notes 3.15% due 2026 (C)	1,951,470,000	3,233,353
29	Senior Notes 3.30% due 2027 (B)	400,000,000	3,306,994
30			1,420,000 D
31	Senior Notes 3.30% due 2027 (B)	1,150,000,000	9,322,742
32			3,404,000 D
33	TOTAL	42,665,040,000	476,806,155

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	Senior Notes 3.75% due 2028 (C)	875,000,000	3,645,283
2	Senior Notes 4.65% due 2028 (B)	300,000,000	2,587,342
3			852,000 D
4	Senior Notes 4.55% due 2030 (C)	3,100,000,000	44,414,717
5	Senior Notes 6.05% due 2034 (A)	3,000,000,000	30,717,515
6			14,640,000 D
7	Senior Notes 5.80% due 2037 (A)	700,000,000	6,807,234
8			3,822,000 D
9	Senior Notes 5.80% due 2037 (A)	250,000,000	2,562,097
10			3,862,500 D
11	Senior Notes 6.35% due 2038 (A)	400,000,000	3,943,976
12			568,000 D
13	Senior Notes 6.25% due 2039 (A)	550,000,000	5,145,853
14			6,814,500 D
15	Senior Notes 5.40% due 2040 (A)	550,000,000	5,435,842
16			7,815,500 D
17	Senior Notes 5.40% due 2040 (A)	250,000,000	2,459,767
18			6,252,500 D
19	Senior Notes 4.50% due 2040 (C)	1,951,470,000	3,233,353
20	Senior Notes 4.50% due 2041 (B)	250,000,000	2,576,302
21			862,500 D
22	Senior Notes 4.45% due 2042 (B)	400,000,000	4,062,665
23			2,036,000 D
24	Senior Notes 3.75% due 2042 (B)	350,000,000	3,632,775
25			311,500 D
26	Senior Notes 4.60% due 2043 (B)	375,000,000	3,768,714
27			303,750 D
28	Senior Notes 5.125% due 2043 (A)	500,000,000	5,099,524
29			765,000 D
30	Senior Notes 4.75% due 2044 (B)	450,000,000	4,685,301
31			1,921,500 D
32	Senior Notes 4.75% due 2044 (B)	225,000,000	2,298,853
33	TOTAL	42,665,040,000	476,806,155

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			-13,594,500 P
2	Senior Notes 4.30% due 2045 (B)	500,000,000	5,051,799
3			5,745,000 D
4	Senior Notes 4.30% due 2045 (B)	100,000,000	1,092,707
5			5,231,000 D
6	Senior Notes 4.25% due 2046 (B)	450,000,000	4,859,582
7			8,415,000 D
8	Senior Notes 4.00% due 2046 (B)	400,000,000	4,345,973
9			7,344,000 D
10	Senior Notes 4.00% due 2046 (B)	200,000,000	2,102,746
11			4,136,000 D
12	Senior Notes 3.95% due 2047 (B)	850,000,000	8,803,613
13			3,706,000 D
14	Senior Notes 4.95% due 2050 (C)	3,100,000,000	44,414,717
15			
16	Pollution Control Bonds 1996 Series C (A)	200,000,000	1,001,412
17	Pollution Control Bonds 1996 Series E (A)	165,000,000	927,332
18	Pollution Control Bonds 1996 Series F (A)	100,000,000	556,667
19	Pollution Control Bonds 1997 Series B (A)	148,550,000	886,179
20	Pollution Control Bonds 2008 Series F, 1.75% (A) (E)	50,000,000	164,224
21	Pollution Control Bonds 2009 Series A (A)	74,275,000	403,242
22	Pollution Control Bonds 2009 Series B (A)	74,275,000	403,242
23	Pollution Control Bonds 2010 Series E, 1.75% (A) (E)	50,000,000	328,903
24			
25	3M-LIBOR + 1.48% First Rate Mortgage Bond due 2022	500,000,000	3,153,155
26	First Mortgage Bonds 1.75% due 2022	2,500,000,000	15,699,776
27			150,000 D
28	First Mortgage Bonds 2.10% due 2027	1,000,000,000	7,539,810
29			1,860,000 D
30	First Mortgage Bonds 2.50% due 2031	2,000,000,000	15,563,121
31			2,080,000 D
32	First Mortgage Bonds 3.30% due 2040	1,000,000,000	10,039,810
33	TOTAL	42,665,040,000	476,806,155

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			4,990,000 D
2	First Mortgage Bonds 3.50% due 2050	1,925,000,000	19,311,372
3			12,146,750 D
4	Debtor-In-Possession Credit Facility - Term Loan (D)	2,000,000,000	9,187,500
5			
6	Term Loan 18 Months	1,500,000,000	8,500,174
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33	TOTAL	42,665,040,000	476,806,155

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
9/15/2010	10/1/2020	9/15/2010	10/1/2020		7,311,213	1
						2
11/18/2010	10/1/2020	11/18/2010	10/1/2020		3,323,278	3
						4
5/13/2011	5/15/2021	5/13/2011	5/15/2021		3,977,146	5
						6
9/12/2011	9/15/2021	9/12/2011	9/15/2021		3,325,332	7
						8
8/16/2012	8/15/2022	8/16/2012	8/15/2022		5,315,610	9
						10
6/14/2013	6/15/2023	6/14/2013	6/15/2023	375,000,000	12,249,066	11
						12
8/6/2018	8/1/2023	8/6/2018	8/1/2023	500,000,000	20,910,046	13
						14
11/12/2013	11/15/2023	11/12/2013	11/15/2023	300,000,000	11,534,294	15
						16
2/21/2014	2/15/2024	2/21/2014	2/15/2024	450,000,000	16,660,342	17
						18
8/18/2014	8/15/2024	8/18/2014	8/15/2024	350,000,000	11,765,132	19
						20
6/12/2015	6/15/2025	6/12/2015	6/15/2025	400,000,000	14,075,770	21
						22
11/5/2015	6/15/2025	11/5/2015	6/15/2025	200,000,000	7,037,885	23
						24
7/1/2020	7/1/2025	7/1/2020	7/1/2025	875,000,000	15,009,896	25
3/1/2016	3/1/2026	3/1/2016	3/1/2026	600,000,000	17,505,157	26
						27
7/1/2020	1/1/2026	7/1/2020	1/1/2026	1,951,470,000	30,397,064	28
3/10/2017	3/15/2027	3/10/2017	3/15/2027	400,000,000	13,057,981	29
						30
11/29/2017	12/1/2027	11/29/2017	12/1/2027	1,150,000,000	38,078,650	31
						32
				31,852,940,000	909,242,062	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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
7/1/2020	7/1/2028	7/1/2020	7/1/2028	875,000,000	16,315,104	1
8/6/2018	8/1/2028	8/6/2018	8/1/2028	300,000,000	13,702,326	2
						3
7/1/2020	7/1/2030	7/1/2020	7/1/2030	3,100,000,000	70,133,194	4
3/23/2004	3/1/2034	3/23/2004	3/1/2034		40,407,663	5
						6
3/13/2007	3/1/2037	3/13/2007	3/1/2037		9,419,000	7
						8
4/1/2010	3/1/2037	4/1/2010	3/1/2037		3,363,928	9
						10
3/3/2008	2/15/2038	3/3/2008	2/15/2038		5,409,008	11
						12
3/6/2009	3/1/2039	3/6/2009	3/1/2039		7,414,015	13
						14
11/18/2009	1/15/2040	11/18/2009	1/15/2040		7,438,631	15
						16
11/18/2010	1/15/2040	11/18/2010	1/15/2040		3,381,196	17
						18
7/1/2020	7/1/2040	7/1/2020	7/1/2040	1,951,470,000	43,424,377	19
12/1/2011	12/15/2041	12/1/2011	12/15/2041	250,000,000	11,327,039	20
						21
4/16/2012	4/15/2042	4/16/2012	4/15/2042	400,000,000	17,686,275	22
						23
8/16/2012	8/15/2042	8/16/2012	8/15/2042	350,000,000	12,958,044	24
						25
6/14/2013	6/15/2043	6/14/2013	6/15/2043	375,000,000	17,370,594	26
						27
11/12/2013	11/15/2043	11/12/2013	11/15/2043		6,640,396	28
						29
2/21/2014	2/15/2044	2/21/2014	2/15/2044	450,000,000	21,018,372	30
						31
8/18/2014	2/15/2044	8/18/2014	2/15/2044	225,000,000	10,509,186	32
				31,852,940,000	909,242,062	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.
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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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
11/6/2014	3/15/2045	11/6/2014	3/15/2045	500,000,000	21,209,805	2
						3
6/12/2015	3/15/2045	6/12/2015	3/15/2045	100,000,000	4,241,961	4
						5
11/5/2015	3/15/2046	11/5/2015	3/15/2046	450,000,000	18,869,482	6
						7
12/1/2016	12/1/2046	12/1/2016	12/1/2046	400,000,000	16,062,686	8
						9
3/10/2017	12/1/2046	3/10/2017	12/1/2046	200,000,000	8,031,343	10
						11
11/29/2017	12/1/2047	11/29/2017	12/1/2047	850,000,000	33,705,282	12
						13
7/1/2020	7/1/2050	7/1/2020	7/1/2050	3,100,000,000	76,298,750	14
						15
5/23/1996	11/1/2026	5/23/1996	11/1/2026		2,920,976	16
5/23/1996	11/1/2026	5/23/1996	11/1/2026		2,295,599	17
5/23/1996	11/1/2026	5/23/1996	11/1/2026		1,372,680	18
9/16/1997	11/1/2026	9/16/1997	11/1/2026		2,062,796	19
6/15/2017	11/1/2026	6/15/2017	11/1/2026		659,995	20
9/1/2009	11/1/2026	9/1/2009	11/1/2026		1,046,391	21
9/1/2009	11/1/2026	9/1/2009	11/1/2026		1,046,391	22
6/15/2017	11/1/2026	6/15/2017	11/1/2026		659,995	23
						24
6/19/2020	6/16/2022	6/19/2020	6/16/2022	500,000,000	4,772,389	25
6/19/2020	6/16/2022	6/19/2020	6/16/2022	2,500,000,000	23,333,333	26
						27
6/19/2020	8/1/2027	6/19/2020	8/1/2027	1,000,000,000	11,200,000	28
						29
6/19/2020	2/1/2031	6/19/2020	2/1/2031	2,000,000,000	26,666,667	30
						31
6/19/2020	8/1/2040	6/19/2020	8/1/2040	1,000,000,000	17,600,000	32
				31,852,940,000	909,242,062	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.
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		Date From (f)	Date To (g)			
						1
6/19/2020	8/1/2050	6/19/2020	8/1/2050	1,925,000,000	35,933,333	2
						3
4/3/2019	12/31/2020	N/A	N/A		31,112,496	4
						5
7/1/2020	1/1/2022	7/1/2020	1/1/2022	1,500,000,000	18,687,502	6
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				31,852,940,000	909,242,062	33

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

(A) Utility Funded Debt: Interest calculated using Federal Judgement rate of 2.59%. On January 22, 2020, PG&E entered into a Restructuring Support Agreement to refinance its unsecured debt. On July 1, 2020, PG&E issued ~ \$11.9 billion of debt as noted in Note (C) to retire ~ \$9 billion of debt and ~ \$2.9 billion of revolver loan and letter of credit draw.

Schedule Page: 256 Line No.: 11 Column: a

(B) Utility Reinstated Senior Notes: Interest calculated using contractual rates.

Schedule Page: 256 Line No.: 25 Column: a

(C) Utility Long-Term Senior Notes: On July 1, 2020, PG&E issued approx. \$11.9 billion of debt upon emergence from bankruptcy.

Schedule Page: 256.2 Line No.: 20 Column: a

(E) Pollution Control Bonds - On July 1, 2020, PG&E repaid \$100 million of Pollution Control Bonds upon emergence from bankruptcy.

Schedule Page: 256.3 Line No.: 4 Column: a

(D) DIP Term Loan - On July 1, 2020, PG&E repaid \$2 billion of DIP Term Loan upon emergence from bankruptcy.

Schedule Page: 256.3 Line No.: 4 Column: f

Issurance costs were recorded to amortization of debt discounts and expense (428).

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 filed, 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)	410,958,488
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	291,283,203
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	257,167,714
11	Provision for State Income Taxes	150,800,009
12	Per attached schedule (See page 261-1)	1,883,853,411
13		
14	Income Recorded on Books Not Included in Return	
15	AFUDC - Equity and debt	174,768,108
16	Balancing Accounts	1,938,389,931
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Per attached schedule (See page 261-1)	23,455,568,035
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-22,574,663,848
28	Show Computation of Tax:	
29	Federal Tax Net Income as above	
30	Tax at 21% for Electric, Water, Non-Utility, and Gas	-4,740,679,408
31	Other	
32	Add: Tax on FIN 48 Interest	651,449
33	Less: Research & Development Credits	-6,234,175
34	Less: Motor Vehicle Credit	-250,000
35	Reclass Tax Loss to Deferred	4,734,354,291
36	Specified Liability Loss	-11,329,784
37	Subtotal Tax	-23,487,627
38	FIN 48 Tax Adjustments (Net to Gross)	5,397,000
39	Total Tax	-18,090,627
40		
41	Federal Income Tax Accrual	-18,090,627
42		
43		
44		

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 12 Column: b

Annual Report of PACIFIC GAS AND ELECTRIC
COMPANY
Year Ended December 31, 2020

Deductions recorded on books not deducted on
return:

Tax Addback

Bad Debts	112,632,208
Bankruptcy Costs	21,826,958
Capitalized Interest	61,315,619
Compensation Related Adjustments	178,992,375
Depreciation adjustment	336,047,176
DOE Settlement	18,032,732
Executive Compensation	4,637,952
Hydro Decommissioning	12,897,000
Solar and Fuel Cell Decommissioning	6,326,000
Gas Hedge Amortization	3,668,351
Gas Stored Underground Decommissioning	17,762,400
GHG Allowances	588,893,073
Loss on Reacquired Debt	13,881,702
Meals & Entertainment & Lobbying	8,369,049
Wildfire Fund Amortization	245,996,415
Nuclear Decommissioning	50,378,643
Nuclear Fuel expense	109,539,887
Penalties	80,017,028
Plant Disallowance	12,638,843
Total	\$ 1,883,853,411

Deductions on return not charged against book income:

Tax Deduct

Debt Financing Costs	(1,879,614,414)
Computer Software	(114,267,967)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

DCCP Community Payment	(9,794,791)
DIP Financing Fees	(57,058,714)
Earnings of Subsidiaries	(11,791)
Environmental Cleanup	(54,860,613)
Fossil Decommissioning	(2,920,338)
Gas Stored Underground 263A	(480,992)
NorCal Wildfires Reserve	(19,518,630,919)
Property Tax & State Income Tax	(10,680,390)
Repairs	(1,609,916,775)
Retained Decommissioning	(2,255,334)
Section 263A MSCM	(172,342,335)
Other	(22,732,662)
Total	\$ <u>(23,455,568,035)</u>

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

See footnote in row 12, column (b)

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 known, 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal - FICA	9,194,082		125,347,468	120,118,052	
2	Federal - Taxes on Income	314,415,630		-18,090,627	255,363	4,628,087
3	Federal - Unemployment	-45,400		1,118,224	1,109,883	
4	Federal - Decommissioning			26,267,378	26,267,378	
5						
6	SUBTOTAL FEDERAL	323,564,312		134,642,443	147,750,676	4,628,087
7						
8	State - Taxes on Income	139,689,999		13,456,127	112,083	-18,975,571
9	State - Unemployment	239,241		7,439,256	7,411,139	
10						
11	SUBTOTAL STATE TAXES	139,929,240		20,895,383	7,523,222	-18,975,571
12						
13	Ad Valorem property	1,103		488,787,259	524,277,868	35,518,199
14	Other	3,161,439		39,030,940	38,046,053	
15						
16	SUBTOTAL OTHER TAXES	3,162,542		527,818,199	562,323,921	35,518,199
17						
18						
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40						
41	TOTAL	466,656,094		683,356,025	717,597,819	21,170,715

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)	
14,423,498		84,488,679			40,858,789	1
300,697,727		-18,788,436			697,809	2
-37,059		751,942			366,282	3
		26,267,378				4
						5
315,084,166		92,719,563			41,922,880	6
						7
134,058,472		-43,266,945			56,723,072	8
267,358		5,002,474			2,436,782	9
						10
134,325,830		-38,264,471			59,159,854	11
						12
28,693		354,866,840			133,920,419	13
4,146,326		26,553,124			12,477,816	14
						15
4,175,019		381,419,964			146,398,235	16
						17
						18
						19
						20
						21
						22
						23
						24
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						40
453,585,015		435,875,056			247,480,969	41

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 1 Column: l

The following table is included to satisfy requirements for Form 1 and Form 2 reporting of this page:

	Gas (Account 408.1, 409.1) (a)	Non_utility (Account 408.2, 409.2) (b)	Total Other (c)
Federal - FICA (Note 2)	40,858,789	0	40,858,789
Federal - Taxes on Income	46,360	651,449	697,809
Federal - Unemployment	366,282	0	366,282
Total Federal taxes	41,271,431	651,449	41,922,880
State - Taxes on Income	58,493,542	-1,770,469	56,723,073
State - Unemployment	2,436,782	0	2,436,782
Total State	60,930,324	-1,770,469	59,159,855
Ad Valorem property	133,920,419	0	133,920,419
Other	12,477,816	0	12,477,816
Total Other	146,398,235	0	146,398,235

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

Adjustment primarily related to FIN 48 and audit adjustment

Schedule Page: 262 Line No.: 8 Column: f

Adjustment primarily related to FIN 48 and audit adjustment

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

Adjustment reflects a portion of property taxes paid on construction work in progress. The amount charged during the year was reduced and capitalized to certain assets under construction.

Schedule Page: 262 Line No.: 14 Column: a

Balances primarily includes City and County of San Francisco gross receipts and payroll taxes.

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%	84,072,608			411.5	5,800,766	
6							
7							
8	TOTAL	84,072,608				5,800,766	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	10%	18,812,494			411.5	1,191,046	
12							
13	TOTAL	18,812,494				1,191,046	
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
78,271,842	18		5
			6
			7
78,271,842			8
			9
			10
17,621,448	22		11
			12
17,621,448			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
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			33
			34
			35
			36
			37
			38
			39
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			41
			42
			43
			44
			45
			46
			47
			48

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	CIAC Deferred Revenue	184,892,865	143,146,456	60,142,031	79,162,214	203,913,048
2						
3	Wildfire Fund		242	192,600,000	1,492,714,149	1,300,114,149
4						
5	Other	57,255,184	Various	42,526,309	54,384,898	69,113,773
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	242,148,049		295,268,340	1,626,261,261	1,573,140,970

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 1 Column: a

Activity includes ~\$48 million of amortization. The deferred credit is amortized over 30 years.

Schedule Page: 269 Line No.: 5 Column: a

"Other" consists of various other deferred credits amounts with balances of less than 5% of the year end balance ($< 1,573,140,970 * 5\% = 78,657,049$).

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 relating 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)	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	Settlement Reg Asset			
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 (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
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							20
							21

NOTES (Continued)

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 272 Line No.: 3 Column: b

No activity in 2020.

ACCUMULATED DEFERRED 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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	5,423,416,109	-256,829,527	-82,350,006
3	Gas	2,607,344,438	8,382,880	-14,015,184
4	Nonutility	432,084,112		
5	TOTAL (Enter Total of lines 2 thru 4)	8,462,844,659	-248,446,647	-96,365,190
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	8,462,844,659	-248,446,647	-96,365,190
10	Classification of TOTAL			
11	Federal Income Tax	6,536,756,898	-238,670,003	-69,334,441
12	State Income Tax	1,926,087,761	-9,776,644	-27,030,748
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
					392,520,117	5,641,456,705	2
					212,367,059	2,842,109,561	3
9,595,404			-55,346,682			497,026,198	4
9,595,404			-55,346,682		604,887,176	8,980,592,464	5
							6
							7
							8
9,595,404			-55,346,682		604,887,176	8,980,592,464	9
							10
6,570,048			-38,102,871		434,374,638	6,846,468,893	11
3,025,356			-17,243,812		170,512,538	2,134,123,571	12
							13

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	31,239,819	-3,088,780	-433,646
4	Balancing Accounts	761,989,385	488,675,001	11,558,636
5	Other	653,180,946	-115,548,878	153,848,685
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,446,410,150	370,037,343	164,973,675
10	Gas			
11	Loss on Reacquired Debt	15,716,424	-1,343,711	-113,469
12	Balancing Accounts	202,253,451	37,124,200	-17,720,233
13				
14	Other	7,171,319		1,546,774
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	225,141,194	35,780,489	-16,286,928
18	Other	-21,516,050		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,650,035,294	405,817,832	148,686,747
20	Classification of TOTAL			
21	Federal Income Tax	1,132,154,215	241,118,447	101,716,706
22	State Income Tax	517,881,079	164,699,385	46,970,041
23	Local Income Tax			

NOTES

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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
						28,584,685	3
						1,239,105,750	4
					115,548,878	499,332,261	5
							6
							7
							8
					115,548,878	1,767,022,696	9
							10
						14,486,182	11
						257,097,884	12
							13
						5,624,545	14
							15
							16
						277,208,611	17
780	3					-21,515,273	18
780	3				115,548,878	2,022,716,034	19
							20
534	2				115,548,878	1,387,105,366	21
246	1					635,610,668	22
							23

NOTES (Continued)

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	REGULATORY LIABILITY RETIREM	749,685,174	520	44,112,853	289,605,996	995,178,317
2	Amortization : INDEFINITE					
3	PROCUREMENT ENERGY EFFICIENCY BALANCING	60,707,975	400	184,389,920	182,959,064	59,277,119
4	Amortization : <12 MONTHS					
5	PUBL PURP PROG ENERGY EFFICIENCY BAL ACCT -	14,233,493	400	76,779,085	79,263,114	16,717,522
6	Amortization : <12 MONTHS					
7	PPCBA-Disadv Comm Single Family Solar Homes Subat	2,855,145	400	8,917,700	9,021,555	2,959,000
8	Amortization : <12 MONTHS					
9	MISCELLANEOUS GAS REG LIAB - CURRENT	5,658,622	495	55,124,852	82,046,495	32,580,265
10	Amortization : <12 MONTHS					
11	MISCELLANEOUS ELECTRIC REG LIAB - CURRENT	5,520,201	449	34,743,028	160,892,948	131,670,121
12	Amortization : < 12 MONTHS					
13	PPP SURCHARGE RDD - CURRENT	3,600,455	182.3	10,229,841	10,294,571	3,665,185
14	Amortization : < 12 MONTHS					
15	REG LIABILITY-MISC ELEC CURRENT -FERC INTEREST	78,949,832	400	221,222	3,505,651	82,234,261
16	Amortization : <12 MONTHS					
17	MISCELLANEOUS GAS REG LIAB - NONCURRENT	25,529,009	549	203,819,139	192,104,914	13,814,784
18	Amortization : >12 MONTHS					
19	MISCELLANEOUS ELECTRIC REG LIAB - NONCURRENT	633,392,777	549	1,236,534,761	1,439,996,578	836,854,594
20	Amortization : NO STATED					
21	NON CURRENT REG LIAB-CC8 SETTLEMENT	42,335,168	108	2,260,506	90,977	40,165,639
22	Amortization : 25YEARS					
23	TAMA - GAS	(103,583,344)	182.3	722,012		-104,305,356
24	Amortization : 2 YEARS					
25	REGULATORY LIABILITY TO - CURRENT		400	11,337,578,825	*,*,*,*,*,*	21,879,765
26	Amortization : < 12 MONTHS					
27	SOLAR ON MULTIFAMILY AFFORDABLE HOUSING BAL	87,933,299	400	7,667,286	52,011,371	132,277,384
28	Amortization : < 12 MONTHS					
29	FAS 109 REGULATORY LIABILITY		400	174,873	5,825,803,190	5,825,628,317
30	Amortization : > 12 MONTHS					
31	GAS PRICE RISK MANAGEMENT - CURRENT	1,335,325	807	27,495,017	26,574,517	414,825
32	Amortization : NO STATED					
33	ELECTRIC PRICE RISK MANAGEMENT - CURRENT	28,239,398	555	194,522,538	197,677,226	31,394,086
34	Amortization : NO STATED					
35	FAS 143 REGULATORY LIABILITY	(1,938,296,141)	VARIOUS	292,541,704	28,107,261	-2,202,730,584
36	Amortization : NO STATED					
37	FAS 143 REGULATORY LIABILITY-NUCLEAR DECOMM	3,172,689,361	128	704,951,347	1,132,486,927	3,600,224,941
38	Amortization : NO STATED					
39	FAS 143 REGULATORY LIABILITY	(148,954,572)	VARIOUS	3,663,590		-152,618,162
40	Amortization : NO STATED					
41	TOTAL	3,411,145,909		18,761,727,940	25,237,128,609	9,886,546,578

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	FAS 143 REGULATORY LIABILITY	163,280,033	228.4	5,712,514	7,389,060	164,956,579
2	Amortization : NO STATED					
3	FIN 47 REGULATORY LIABILITY	(873,255,499)	VARIOUS	544,143,610	411,023,117	-1,006,375,992
4	Amortization : NO STATED					
5	CALIFORNIA SOLAR INITIATIVE	57,889,363	400	4,432,018	8,984,768	62,442,113
6	Amortization : < 12 MONTHS					
7	DEMAND RESPONSE EXPENDITURES BALANCING	61,503,379	400	33,978,937	46,110,480	73,634,922
8	Amortization : NO STATED					
9	PPP ENERGY EFFICIENCY-GAS	1,889,463	400	1,751,055	1,571,812	1,710,220
10	Amortization : NO STATED					
11	PPP SURCHARGE ENERGY EFFICIENCY - GAS	11,780,800	400	82,068,581	73,426,003	3,138,222
12	Amortization : < 12 MONTHS					
13	PPP SURCHARGE LOW INCOME - GAS	54,363,148	400	58,874,001	7,752,001	3,241,148
14	Amortization : < 12 MONTHS					
15	GAS PPP SURCHARGE-RDD	(191,748)	400	10,805,313	10,360,550	-636,511
16	Amortization : < 12 MONTHS					
17	NON-TARIFFED PRODUCTS AND SVCS BA-ELECTRIC	571,257	182.3	3,091,360	3,054,382	534,279
18	Amortization : < 12 MONTHS					
19	NON-TARIFFED PRODUCTS AND SVCS BA-GAS	465,118	182.3	624,830	594,470	434,758
20	Amortization : < 12 MONTHS					
21	ON BILL FINANCING BALANCING ELECTRIC	30,249,170	930.2	20,673,032	21,268,226	30,844,364
22	Amortization : NO STATED					
23	ON BILL FINANCING BALANCING GAS	5,286,357	930.2	8,768,682	9,013,133	5,530,808
24	Amortization : NO STATED					
25	ELECTRIC PROGRAM INVESTMENT CHARGE	238,315,154	400	73,634,939	94,803,877	259,484,092
26	Amortization : NO STATED					
27	PROCUREMENT ENERGY EFFICIENCY	8,433,116	400	7,977,515	7,159,666	7,615,267
28	Amortization : NO STATED					
29	SELF GENERATION PROGRAM - ELECTRIC	263,873,397	400	28,973,897	61,366,077	296,265,577
30	Amortization : NO STATED					
31	SELF GENERATION PROGARM-GAS	53,148,406	400	6,360,124	13,437,319	60,225,601
32	Amortization : NO STATED					
33	PPP (PPPLIBA)-GAS	31,234,556	400	66,188,682	69,196,152	34,242,026
34	Amortization : < 12 MONTHS					
35	PPP (PPPLIBA)-ELECTRIC	193,399,246	400	130,293,264	100,064,139	163,170,121
36	Amortization : < 12 MONTHS					
37	SW MARKETING, EDUCATION AND OUTREACH	4,989,277	400	9,799,802	11,586,637	6,776,112
38	Amortization : < 12 MONTHS					
39	SW MARKETING, EDUCATION AND OUTREACH	837,394	400	1,084,030	1,283,177	1,036,541
40	Amortization : < 12 MONTHS					
41	TOTAL	3,411,145,909		18,761,727,940	25,237,128,609	9,886,546,578

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	GPBA - GREENHOUSE GAS REVENUE SUBACCOUNT	6,243,560	400	167,832,648	145,299,147	-16,289,941
2	Amortization : < 12 MONTHS					
3	GHGRBA - GREENHOUSE GAS REVENUE	25,038,303	400	460,161,190	386,782,591	-48,340,296
4	Amortization : NO STATED					
5	CA ENERGY SYSTEMS FOR 21ST CENTURY B/A-ELEC -	745,975	182.3	10,503	24,296	759,768
6	Amortization : 5 YEARS					
7	GPBA - LOW CARBON FUELS STANDARD REVENUE	521,864	400	562,601	176,856	136,119
8	Amortization : < 12 MONTHS					
9	GHGRBA - LOW CARBON FUELS STANDARD REVENUE	156,543,316	400	108,887,430	100,079,007	147,734,893
10	Amortization : < 12 MONTHS					
11	ENGINEERING CRTICIAL ASSESSMENT BAL NC	15,878,253	182.3	42,264,427	15,204,707	-11,181,467
12	Amortization : >12 MONTHS					
13	ELECT VEHICLE PRGM BA CURRENT	19,820,982	400	41,564,897	47,405,310	25,661,395
14	Amortization : < 12 MONTHS					
15	RULE 20A BALANCING ACCOUNT (RBA) NONCURRENT	11,818,144	400	35,080,536	34,055,491	10,793,099
16	Amortization : > 12 MONTHS					
17	GPBA-BIOMETHANE ENVIRONMENTAL PROCEEDS		400		430,217	430,217
18	Amortization : > 12 MONTHS					
19	STATEWIDE ENERGY EFFICIENCY BALANCING		400	17,442,642	14,886,137	-2,556,505
20	Amortization : AMORTIZATION : < 12 MONTHS					
21	STATEWIDE ENERGY EFFICIENCY BALANCING		400	4,360,623	3,721,496	-639,127
22	Amortization : AMORTIZATION : < 12 MONTHS					
23	FAS143 REGLIAB GUS LM and PC	17,762,400	228.4		17,762,400	35,524,800
24	Amortization : NO STATED					
25	HYDROSTATIC TESTING BAL ACCOUNT		400	31,344,626	84,362,934	53,018,308
26	Amortization : >12 MONTHS					
27	ATMOSPHERIC CORROSION BAL ACCT		400	1,438,353	2,258,763	820,410
28	Amortization : >12 MONTHS					
29	FAS REGULATORY LIABILITY - HYDRO		228.4		12,897,000	12,897,000
30	Amortization : Not Stated					
31	FAS REGULATORY LIABILITY - OTHER ELECTRIC		228.4		6,326,000	6,326,000
32	Amortization : Not Stated					
33	ELECTRIC PRICE RISK MANAGEMENT - NONCURRENT	123,659,056	555	750,335,790	762,594,351	135,917,617
34	Amortization : NO STATED					
35	Miscellaneous minor items	3,221,492	VARIOUS	1,574,755,389	1,571,515,915	-17,982
36						
37						
38						
39						
40						
41	TOTAL	3,411,145,909		18,761,727,940	25,237,128,609	9,886,546,578

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 35 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278 Line No.: 39 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278.1 Line No.: 3 Column: c

Offset to account 108 - Accumulated Depreciation, and 230 - ARO - Liability.

Schedule Page: 278.2 Line No.: 35 Column: c

Activity primarily related to DREBA OPERATIONS BALANCING ACCOUNT - CURRENT, DISTRIBUTION RESOURCES PLAN DEMONSTRATION BAL ACCT CURR, NGLAPBA - CURRENT, and Dairy Biomethane Pilot Balancing Account with offset to 400.

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	5,522,669,106	4,846,946,484
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	6,193,136,336	5,862,972,960
5	Large (or Ind.) (See Instr. 4)	1,530,028,729	1,493,456,812
6	(444) Public Street and Highway Lighting	61,588,250	58,051,541
7	(445) Other Sales to Public Authorities	1,819,316	2,184,785
8	(446) Sales to Railroads and Railways	6,055,152	7,244,471
9	(448) Interdepartmental Sales	51,081,618	48,794,887
10	TOTAL Sales to Ultimate Consumers	13,366,378,507	12,319,651,940
11	(447) Sales for Resale	1,897,859,429	1,462,736,215
12	TOTAL Sales of Electricity	15,264,237,936	13,782,388,155
13	(Less) (449.1) Provision for Rate Refunds	62,826,628	-308,209,362
14	TOTAL Revenues Net of Prov. for Refunds	15,201,411,308	14,090,597,517
15	Other Operating Revenues		
16	(450) Forfeited Discounts	733,289	3,013,879
17	(451) Miscellaneous Service Revenues	7,472,766	8,400,066
18	(453) Sales of Water and Water Power	4,720,958	3,769,463
19	(454) Rent from Electric Property	98,163,916	83,262,832
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-197,139,050	-252,724,684
22	(456.1) Revenues from Transmission of Electricity of Others	2,874,769	2,558,524
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25	(400) Balancing Accounts	672,568,442	303,287,176
26	TOTAL Other Operating Revenues	589,395,090	151,567,256
27	TOTAL Electric Operating Revenues	15,790,806,398	14,242,164,773

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.

8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.

9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
29,814,086	27,513,436	4,910,767	4,845,484	2
				3
33,954,854	35,098,781	641,984	641,100	4
14,100,505	14,711,024	1,287	1,288	5
291,953	296,641	36,492	36,176	6
8,701	10,879	4	5	7
326,696	440,880	28	28	8
296,120	300,575			9
78,792,915	78,372,216	5,590,562	5,524,081	10
18,328,235	21,907,744			11
97,121,150	100,279,960	5,590,562	5,524,081	12
				13
97,121,150	100,279,960	5,590,562	5,524,081	14

Line 12, column (b) includes \$ 70,574,259 of unbilled revenues.
 Line 12, column (d) includes 0 MWH relating to unbilled revenues

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

Line 4 includes all other commercial and industrial customers including irrigation pumping.

Schedule Page: 300 Line No.: 4 Column: c

Line 4 includes all other commercial and industrial customers including irrigation pumping.

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

Line 5 includes commercial and industrial customers with demands of 1,000 Kw or greater.

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

Line 5 includes commercial and industrial customers with demands of 1,000 Kw or greater.

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

Column (b) includes California Department of Water Resources ("DWR") revenues of \$416,607,371 which was deducted from Line 21 below.

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

Column (b) includes California Department of Water Resources ("DWR") revenues of \$367,368,862 which was deducted from Line 21 below.

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

This consists of :

NSF fees and rent charges to customers' refundable deposits	1,455,932
Misc Elec Svs RevPro	3,760
NRD Revenue	1,429,251
MLX billings to electric residential customers	3,034,496
MLX billings to electric non-residential customers	966,915
Reimbursable third-party labor requested on behalf of customers	582,412
	7,472,766
Total	7,472,766

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

This consists of:

1 NSF fees and rent charges to customers' refundable deposits	1,700,170
2 NRD Revenue	1,822,179
3 MLX billings to electric residential customers	3,246,059
4 MLX billings to electric non-residential customers	954,594
5 Reimbursable third-party labor requested on behalf of customers	677,064
	8,400,066
Total	8,400,066

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

This consists of :

Unbilled revenues

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

	70,574,259
Reimbursement to the Utility for costs spent on customer projects	39,784,410
Reimbursement to the Utility for costs spent on customer billing	13,757,318
Reimbursement fees paid to the CPUC based on sales	(56,360,402)
Employee transfer fees	71,012
Other revenue-damage claim	2,382,664
Recreational Facilities Revenue	523,630
Revenue assigned - base	(32,969,093)
Pass-through franchise fees and uncollectible revenue	32,969,881
Transition Cost Revenue Account for non-bypassable charges	32,208,380
Fees for utility energy service contracts	52,107,815
Other electric revenues not classified elsewhere	63,723,129
MCI rights of way	650,161
DWR	(416,607,371)
Miscellaneous (items under \$250,000)	45,157
	<hr/>
Total	(197,139,050)

The DWR revenues of \$416,607,371 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

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

This consists of :

Unbilled revenues	(39,025,952)
Reimbursement to the Utility for costs spent on customer projects	30,211,138
Reimbursement to the Utility for costs spent on customer billing	12,843,596
Reimbursement fees paid to the CPUC based on sales	(42,640,694)
Employee transfer fees	185,885
Other revenue-damage claim	1,255,339

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
PACIFIC GAS AND ELECTRIC COMPANY			

FOOTNOTE DATA

Recreational Facilities Revenue	1,085,671
Revenue assigned - base	(24,165,208)
Pass-through franchise fees and uncollectible revenue	24,165,208
Transition Cost Revenue Account for non-bypassable charges	38,034,266
Fees for utility energy service contracts	52,451,511
Other electric revenues not classified elsewhere	59,451,590
MCI rights of way	650,161
DWR	(367,368,862)
Miscellaneous (items under \$250,000)	<u>141,667</u>
 Total	 (252,724,684)

The DWR revenues of \$367,368,862 represents amount passed through to the DWR. The Utility acts as a pass-through entity for DWR charges collected from the Utility's customers. Although charges for the DWR are included in total electric revenues, the Utility deducts pass through amounts from electric revenues. These pass-through revenues are excluded from the Utility's electric revenues in its Statement of Income.

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					
5					
6					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales:					
2	E1 Individually Metered	17,355,610	3,546,352,652	3,072,483	5,649	0.2043
3	EL1 Residential Care Program S	7,502,670	1,004,008,254	1,161,835	6,458	0.1338
4	E6 Residential Time-of-Use Servic	416,524	83,575,738	78,679	5,294	0.2007
5	EL6 Residential Care Time-of-U	39,852	5,167,737	6,214	6,413	0.1297
6	E7 Time-of-Use	-3	-33			0.0110
7	ETOUA Residential Time-of-Use Ser	538,836	123,139,972	159,653	3,375	0.2285
8	EL-TOUA Residential Care Time-of-	122,878	16,324,384	28,480	4,315	0.1329
9	ETOUB Residential Time-of-Use Ser	1,111,761	245,283,555	89,972	12,357	0.2206
10	EL-TOUB Residential Care Time-of-	231,249	32,825,135	21,302	10,856	0.1419
11	ETOUC Residential Time-of-Use Ser	904,711	204,050,870	159,143	5,685	0.2255
12	EL-TOUC Residential Care Time-of-	189,080	25,861,121	33,342	5,671	0.1368
13	ETOUD Residential TOU Peak Pricin	139,251	24,783,724	16,186	8,603	0.1780
14	ECLSD		785			
15	EVA Residential TOU Service for P	73,782	10,887,012	13,774	5,357	0.1476
16	EVB Residential TOU Service for P	1,006	157,898	395	2,547	0.1570
17	EV2A Residential TOU Service for	510,512	89,026,762	50,204	10,169	0.1744
18	EM Master-Metered Multi-family Se	212,480	37,892,459	15,459	13,745	0.1783
19	EML Multifamily CARE Program - Ma	24,942	2,252,492	186	134,097	0.0903
20	EMTOU Residential Time of Use Ser	3,763	929,816	609	6,179	0.2471
21	ES Multi-family Service	23,776	3,665,249	285	83,425	0.1542
22	ESL Multifamily CARE Program Serv	24,816	3,872,676	253	98,087	0.1561
23	ESR RV Park and Residential Marin	2,279	422,268	31	73,516	0.1853
24	ESRL RV Park and Residential Mari	10,765	1,868,797	84	128,155	0.1736
25	ET Mobilehome Park Service	15,735	2,788,170	284	55,405	0.1772
26	ETL Low-Income Mobile Home	355,637	57,101,978	1,886	188,567	0.1606
27	SE1 Standby - Individually Metere	81	29,359	2	40,500	0.3625
28	SEM1 Standby - Master-Metered Mul	1,965	325,893	10	196,500	0.1658
29	STOUS Standby - TOU Secondary -		60,471	14		
30	SETOUB Standby Service	25	10,291	1	25,000	0.4116
31	SEV2A Standby Service	30	3,621	1	30,000	0.1207
32	UNCLASSIFIED	74				
33	Total Residential	29,814,087	5,522,669,106	4,910,767	6,071	0.1852
34						
35						
36						
37						
38						
39						
40	442 Commercial and Industrial Sal					
41	TOTAL Billed	78,792,911	15,264,237,936	5,590,562	14,094	0.1937
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,792,911	15,264,237,936	5,590,562	14,094	0.1937

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	A1 Small General Service	1,078,983	214,603,001	49,005	22,018	0.1989
2	A1F Small General Service	71,976	16,357,416	17,521	4,108	0.2273
3	A1X Small General Service	4,619,660	1,013,403,299	341,919	13,511	0.2194
4	A15 Small General Service	355	204,722	346	1,026	0.5767
5	A6 Time-of-Use	994,204	219,438,248	25,324	39,259	0.2207
6	A10 Medium General	6,914,099	1,249,190,883	40,251	171,775	0.1807
7	E19 500 to 999 Kw Demand	11,743,352	1,660,518,609	27,875	421,286	0.1414
8	E20 1000 Kw Demand or More	11,483,676	1,207,040,170	917	12,523,093	0.1051
9	AG1 Agricultural Power	68,080	21,701,659	4,137	16,456	0.3188
10	AG4 TOU Agricultural Power	1,329,724	409,072,241	54,343	24,469	0.3076
11	AGA, AGB, ACG TOU Agricultural	247,323	56,975,273	3,463	71,419	0.2304
12	AGF Flexible Off-Peak TOU Agricul	20,557	4,663,548	246	83,565	0.2269
13	AG5 Large TOU Agricultural Power	4,920,466	959,926,478	25,847	190,369	0.1951
14	AGR Split-Wk TOU Agricultural Pow	32,782	10,185,750	1,708	19,193	0.3107
15	AGV Short-Pk TOU Agricultural Pow	24,648	6,945,324	1,161	21,230	0.2818
16	B1 Small General Service	346,870	75,244,305	21,886	15,849	0.2169
17	B6 Small General Time-of-Use Serv	153,644	32,385,035	9,318	16,489	0.2108
18	B10 Medium General Demand	545,678	104,618,104	2,494	218,796	0.1917
19	B19 Medium Demand Metered TOU	707,406	107,007,446	1,597	442,959	0.1513
20	B20 Service to Customers with Max	908,335	92,853,412	88	10,321,989	0.1022
21	BEV Business Electric Vehicle	54,369	7,733,723	113	481,142	0.1422
22	OL1 Outdoor Area Lighting Service	5,423	2,669,980	12,917	420	0.4923
23	SA1 Standby & General Service	-2,825	12,442	7	-403,571	-0.0044
24	SA6 Standby & Small TOU	21,687	1,332,976	11	1,971,545	0.0615
25	SA10 Standby & Alt. Rate for Med-	10,033	1,750,224	20	501,650	0.1744
26	SB Standby Electric	38,232	5,430,629	17	2,248,941	0.1420
27	SE19 Standby & 500 to 999 Kw	21,646	2,734,920	40	541,150	0.1263
28	SE20 Standby & 1000 Kw Demand	1,367,905	164,481,066	83	16,480,783	0.1202
29	STOUP Standby - TOU Primary	-38,020	11,809,986	256	-148,516	-0.3106
30	STOUS Standby - TOU Secondary -	2,496	1,842,889	114	21,895	0.7383
31	STOUT Standby - TOU Transformer	349,388	59,279,116	244	1,431,918	0.1697
32	UNCLASSIFIED	13,204	1,752,191	3	4,401,333	0.1327
33						
34						
35						
36	Total Commercial and Industrial	48,055,356	7,723,165,065	643,271	74,705	0.1607
37						
38						
39						
40						
41	TOTAL Billed	78,792,911	15,264,237,936	5,590,562	14,094	0.1937
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,792,911	15,264,237,936	5,590,562	14,094	0.1937

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						
2						
3						
4						
5						
6	444 Public Street and Highway Lig					
7	LS1-A Utility-Owned Street & High	11,148	6,655,133	5,157	2,162	0.5970
8	LS1-B Utility-Owned Street & High	3	1,492	2	1,500	0.4973
9	LS1-C Utility-Owned Street & High	4,233	2,185,031	555	7,627	0.5162
10	LS1-D Utility-Owned Street & High	7,473	3,738,828	1,088	6,869	0.5003
11	LS1-E Utility-Owned Street & High	8,041	6,394,234	1,803	4,460	0.7952
12	LS1-F Utility-Owned Street & High	3,451	2,114,797	1,606	2,149	0.6128
13	LS2-A Customer-Owned Street & Hig	202,858	29,448,443	9,692	20,930	0.1452
14	LS2-C Customer-Owned Street & Hig	2,932	707,128	385	7,616	0.2412
15	LS3 Cust-Owned Street & Highway L	7,896	1,312,440	1,506	5,243	0.1662
16	LS3-F Cust-Owned Street & Highway	4,108	748,271	2,209	1,860	0.1821
17	TC1 Traffic Control Service	38,599	8,010,743	11,906	3,242	0.2075
18	TC1F Traffic Control Service	1,209	271,710	583	2,074	0.2247
19						
20	Total Public Street and Highway	291,951	61,588,250	36,492	8,000	0.2110
21						
22	445 Other Sales to Public Authori					
23	Special Contracts	8,701	1,819,316	4	2,175,250	0.2091
24	Total Other Sales to Public Aut	8,701	1,819,316	4	2,175,250	0.2091
25						
26	446 Sales to Railroads and Railwa					
27	Special Contracts	326,696	6,055,152	28	11,667,714	0.0185
28	Total Sales to Railroads and Ra	326,696	6,055,152	28	11,667,714	0.0185
29						
30	447 Sales for Resale					
31	Special Contracts		1,897,859,429			
32	Total Sales for Resale		1,897,859,429			
33						
34	448 Interdepartmental Sales	296,120	51,081,618			0.1725
35	Total Interdepartmental Sales	296,120	51,081,618			0.1725
36						
37						
38						
39						
40						
41	TOTAL Billed	78,792,911	15,264,237,936	5,590,562	14,094	0.1937
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	78,792,911	15,264,237,936	5,590,562	14,094	0.1937

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 not 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 long-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)	Average Monthly CP Demand (f)
1	RQ Sales:					
2	Silicon Valley Power	RQ	248			
3	California Independent System Operator	RQ	6			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
					2
18,328,235		426,288,961	1,471,570,468	1,897,859,429	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
18,328,235	0	426,288,961	1,471,570,468	1,897,859,429	
0	0	0	0	0	
18,328,235	0	426,288,961	1,471,570,468	1,897,859,429	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 2 Column: a

- Sales represent the Grizzly Power Sale.
 - Silicon Valley Power was formally the City of Santa Clara.
- The Rate Schedule for Grizzly was changed in FERC Docket No. ER17-1752-000.

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

Represents amounts included in ISO Settlement Statement on page 397.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,142	6,129
5	(501) Fuel	184,061,721	204,525,672
6	(502) Steam Expenses	11,238	10,488
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	19,142	66,148
11	(507) Rents		
12	(509) Allowances	37,602,471	33,701,353
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	221,695,714	238,309,790
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	23,428	39,355
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	1,343,014	2,192,474
18	(513) Maintenance of Electric Plant	945,338	10,822,436
19	(514) Maintenance of Miscellaneous Steam Plant	2,307,586	5,534,351
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	4,619,366	18,588,616
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	226,315,080	256,898,406
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	5,839,138	4,915,613
25	(518) Fuel	110,507,650	113,567,860
26	(519) Coolants and Water	31,711,282	35,186,370
27	(520) Steam Expenses	40,847,332	41,818,534
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,727,700	4,021,766
31	(524) Miscellaneous Nuclear Power Expenses	231,270,908	222,449,476
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	422,904,010	421,959,619
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,245,067	2,623,727
36	(529) Maintenance of Structures	3,354,092	4,274,664
37	(530) Maintenance of Reactor Plant Equipment	30,162,140	31,444,584
38	(531) Maintenance of Electric Plant	34,113,684	42,240,924
39	(532) Maintenance of Miscellaneous Nuclear Plant	48,223,871	115,868,215
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	118,098,854	196,452,114
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	541,002,864	618,411,733
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,168,007	439,376
45	(536) Water for Power	2,638,553	1,662,236
46	(537) Hydraulic Expenses	2,283,235	2,170,419
47	(538) Electric Expenses	34,053,376	25,142,375
48	(539) Miscellaneous Hydraulic Power Generation Expenses	73,827,172	68,497,209
49	(540) Rents	822,487	803,141
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	115,792,830	98,714,756
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	684,008	1,210,247
54	(542) Maintenance of Structures	4,656,985	3,991,198
55	(543) Maintenance of Reservoirs, Dams, and Waterways	37,001,129	28,368,557
56	(544) Maintenance of Electric Plant	23,583,421	21,946,833
57	(545) Maintenance of Miscellaneous Hydraulic Plant	6,559,988	7,060,275
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	72,485,531	62,577,110
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	188,278,361	161,291,866

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	141,639	202,870
63	(547) Fuel		
64	(548) Generation Expenses	12,633,268	10,779,037
65	(549) Miscellaneous Other Power Generation Expenses	12,106,252	4,027,747
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	24,881,159	15,009,654
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	18,035	46,074
70	(552) Maintenance of Structures	2,631,322	2,528,626
71	(553) Maintenance of Generating and Electric Plant	6,387,016	3,993,115
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,663,973	1,501,125
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	10,700,346	8,068,940
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	35,581,505	23,078,594
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	4,613,389,452	4,058,377,103
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	95,904,654	174,226,755
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	4,709,294,106	4,232,603,858
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,700,471,916	5,292,284,457
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,667,989	6,397,496
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	52,126,090	34,154,856
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	19,933,393	20,057,993
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	12,024,360	7,710,341
93	(562) Station Expenses	9,989,805	8,684,009
94	(563) Overhead Lines Expenses	96,929,276	78,078,057
95	(564) Underground Lines Expenses	310,365	235,377
96	(565) Transmission of Electricity by Others	1,007,240	1,014,722
97	(566) Miscellaneous Transmission Expenses	165,381,930	183,864,519
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	361,370,448	340,197,370
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,450,242	1,336,831
102	(569) Maintenance of Structures	868,048	1,025,132
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	50,326,017	41,789,620
108	(571) Maintenance of Overhead Lines	281,226,572	608,246,266
109	(572) Maintenance of Underground Lines	2,258,948	1,787,030
110	(573) Maintenance of Miscellaneous Transmission Plant	464,714	493,625
111	TOTAL Maintenance (Total of lines 101 thru 110)	337,594,541	654,678,504
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	698,964,989	994,875,874

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	9,782,303	13,723,909
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	9,782,303	13,723,909
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 Exps (Total 123 and 130)	9,782,303	13,723,909
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	20,709,462	6,014,879
135	(581) Load Dispatching		
136	(582) Station Expenses	5,081,362	3,079,056
137	(583) Overhead Line Expenses	67,025,442	41,788,851
138	(584) Underground Line Expenses	58,350,200	47,446,039
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,549,953	1,073,918
141	(587) Customer Installations Expenses	16,827,291	14,723,638
142	(588) Miscellaneous Expenses	650,635,035	414,577,885
143	(589) Rents	448,661	569,576
144	TOTAL Operation (Enter Total of lines 134 thru 143)	820,627,406	529,273,842
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	-4,640,219	6,211,857
147	(591) Maintenance of Structures	3,497,667	1,132,501
148	(592) Maintenance of Station Equipment	48,931,712	48,729,079
149	(593) Maintenance of Overhead Lines	2,023,359,973	775,894,931
150	(594) Maintenance of Underground Lines	40,316,858	49,179,380
151	(595) Maintenance of Line Transformers	2,683,080	1,509,530
152	(596) Maintenance of Street Lighting and Signal Systems	1,602,826	1,543,961
153	(597) Maintenance of Meters	10,029,432	8,695,292
154	(598) Maintenance of Miscellaneous Distribution Plant	1,158,682	1,585,045
155	TOTAL Maintenance (Total of lines 146 thru 154)	2,126,940,011	894,481,576
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	2,947,567,417	1,423,755,418
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	5,729,173	6,778,388
160	(902) Meter Reading Expenses	6,940,157	6,653,089
161	(903) Customer Records and Collection Expenses	213,766,303	204,050,050
162	(904) Uncollectible Accounts	104,122,312	34,941,999
163	(905) Miscellaneous Customer Accounts Expenses	865,493	1,308,400
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	331,423,438	253,731,926

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	351,431,709	462,729,169
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	295,649	162,912
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	351,727,358	462,892,081
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,214,952	1,039,813
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	2,214,952	1,039,813
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	307,671,632	398,482,342
182	(921) Office Supplies and Expenses	91,699,147	73,887,712
183	(Less) (922) Administrative Expenses Transferred-Credit	82,886,864	103,181,563
184	(923) Outside Services Employed	497,380,727	568,349,816
185	(924) Property Insurance	7,948,063	13,751,290
186	(925) Injuries and Damages	1,198,782,625	11,371,690,540
187	(926) Employee Pensions and Benefits	336,845,887	357,000,223
188	(927) Franchise Requirements	99,830,022	89,389,579
189	(928) Regulatory Commission Expenses		
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	27,790,938	23,019,768
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	2,485,062,177	12,792,389,707
195	Maintenance		
196	(935) Maintenance of General Plant	3,482,559	4,229,193
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	2,488,544,736	12,796,618,900
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	12,530,697,109	21,238,922,378

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 76 Column: b

Of the year end balance, \$187,246 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 76 Column: c

Of the year end balance, \$124,788 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: b

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 107 Column: c

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: b

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 136 Column: c

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: b

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 142 Column: c

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: b

Of the year end balance, \$52,154 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 148 Column: c

Of the year end balance, \$614,883 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: b

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

Schedule Page: 320 Line No.: 187 Column: c

Of the year end balance, \$0 relates to energy storage operation per FERC Order 784.

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)	Average Monthly CP Demand (f)
1	QUALIFYING FACILITIES (QF's)					
2	RENEWABLES:					
3	BIOGAS - CITY OF WATSONVILLE	LU		0.00000	0.16940	N/A
4	MONTEREY REGIONAL WATER	LU		0.00000	0.18640	N/A
5	HYDRO - JOHN NEERHOUT JR.	LU		0.00000	0.01130	N/A
6	YELLOWJACKET VENTURE LLC	LU		0.00000	0.01130	N/A
7	GANSNER HYDRO	LU		0.00000	0.00000	N/A
8	HYPOWER INC.	LU		0.00000	4.54050	N/A
9	JAMES B. PETER	LU		0.00000	0.01560	N/A
10	JAMES CRANE HYDRO	LU		0.00000	0.00090	N/A
11	HYDRO SIERRA DEADWOOD CREEK	LU		0.00000	1.13200	N/A
12	HYDRO SIERRA DEADWOOD PURPA	LU		0.00000	0.25770	N/A
13	EL DORADO MONTGOMERY CREEK	LU		0.00000	0.00000	N/A
14	SNOW MOUNTAIN COVE	LU		0.00000	4.68420	N/A
	Total					

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	SNOW MOUNTAIN BURNEY CREEK	LU		0.00000	1.21900	N/A
2	OLSEN POWER PARTNERS	LU		0.00000	0.00000	N/A
3	OLSEN POWER QPA	LU		0.00000	3.45050	N/A
4	SNOW MT. PONDEROSA BAILEY CREEK	LU		0.00000	0.66970	N/A
5	MALACHA HYDRO L.P.	LU		0.00000	16.52960	N/A
6	LOFTON RANCH	LU		0.00000	0.09830	N/A
7	HAT CREEK HEREFORD RANCH	LU		0.00000	0.04310	N/A
8	STEVE & BONNIE TETRICK	LU		0.00000	0.00000	N/A
9	EIF HAYPRESS LLC	LU		0.00000	1.23460	N/A
10	EAGLE HYDRO	LU		0.00000	0.00000	N/A
11	CHARCOAL RAVINE	LU		0.00000	0.00050	N/A
12	SWISS AMERICA	LU		0.00000	0.03720	N/A
13	WRIGHT RANCH HYDROELECTRIC	LU		0.00000	0.00000	N/A
14	SCHAADS HYDRO	LU		0.00000	0.04990	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ROCK CREEK WATER DISTRICT	LU		0.00000	0.15300	N/A
2	TOM BENNINGHOVEN	LU		0.00000	0.00000	N/A
3	ORANGE COVE IRRIGATION DISTRICT	LU		0.00000	0.43580	N/A
4	FISHWATER RELEASE	LU		0.00000	0.27320	N/A
5	KINGS RIVER HYDRO	LU		0.00000	0.29640	N/A
6	ETIWANDA POWER PLANT	LU		0.00000	1.35000	N/A
7	SOLAR- VILLA SORRISO SOLAR	LU		0.00000	0.00000	N/A
8	WIND- DONALD R. CHENOWETH	LU		0.00000	0.00000	N/A
9	COGEN - CROCKETT COGEN	LU		240.00000	235.69920	N/A
10	PHILLIPS 66	LU		0.00000	9.42550	N/A
11	BERKELEY COGENERATION	LU		0.00000	3.53140	N/A
12	STANFORD ENERGY GROUP	LU		0.00000	0.00000	N/A
13	ECO SERVICES OPERATIONS LLC	LU		0.00000	0.18630	N/A
14	SATELLITE SENIOR HOMES	LU		0.00000	0.00840	N/A
	Total					

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(Including power exchanges)

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1	HAYWARD AREA RECREATION AND PARK	LU		0.00000	0.03730	N/A
2	CHEVRON RICHMOND REFINERY	LU		0.00000	5.69170	N/A
3	ORINDA SENIOR VILLAGE	LU		0.00000	0.01650	N/A
4	SRI INTERNATIONAL	LU		0.00000	1.69060	N/A
5	ARDEN WOOD BENEVOLENT ASSOC.	LU		0.00000	0.00140	N/A
6	1080 CHESTNUT CORP.	LU		0.00000	0.01930	N/A
7	NIHONMACHI TERRACE	LU		0.00000	0.01990	N/A
8	GREATER VALLEJO RECREATION DIST.	LU		0.00000	0.00800	N/A
9	AIRPORT CLUB	LU		0.00000	0.01780	N/A
10	SANTA CRUZ COUNTY WATER ST. JAIL	LU		0.00000	0.00000	N/A
11	CITY OF MILPITAS	LU		0.00000	0.00000	N/A
12	GREENLEAF UNIT 2	LU		0.00000	0.00000	N/A
13	YUBA CITY COGEN	LU		46.00000	38.73420	N/A
14	YUBA CITY RACQUET CLUB	LU		0.00000	0.00000	N/A
	Total					

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1	FRITO-LAY COGEN QPA2	LU		0.00000	1.13500	N/A
2	FRESNO COGEN LP	LU		0.00000	6.95820	N/A
3	PE KES KINGSBURG LLC	LU		34.50000	16.80030	N/A
4	EOR- CHEVRON MCKITTRICK FHP	LU		0.00000	4.91060	N/A
5	CHEVRON USA TAFT/CADET	LU		0.00000	2.94960	N/A
6	CHEVRON USA CYMRIC	LU		0.00000	5.08610	N/A
7	AERA ENERGY SOUTH BELBRIDGE QAA2	LU		0.00000	1.85530	N/A
8	CHEVRON USA COALINGA	LU		0.00000	4.19580	N/A
9	WESTERN POWER & STEAM INC	LU		17.75000	18.22360	N/A
10	BERRY PETROLEUM CO TANNEHILL 2	LU		7.50000	13.57800	N/A
11	CHEVRON USA INC SE KERN RIVER	LU		0.00000	7.25760	N/A
12	CHEVRON USA INC EASTRIDGE	LU		0.00000	15.74270	N/A
13	AERA ENERGY LLC COALINGA	LU		0.00000	2.04330	N/A
14	FREEMPORT MCMORAN DOME	LU		0.00000	2.70670	N/A
	Total					

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	BILATERALS					
3	2041 ALVARES			0.00000	0.00000	
4	2056 JARDINE			0.00000	0.00000	
5	2059 SCHERZ			0.00000	0.00000	
6	2065 ROGERS			0.00000	0.00000	
7	2081 TERZIAN			0.00000	0.00000	
8	2094 BUZZELLE			0.00000	0.00000	
9	2096 COTTON			0.00000	0.00000	
10	2097 HELTON			0.00000	0.00000	
11	2102 CHRISTENSEN			0.00000	0.00000	
12	2103 HILL			0.00000	0.00000	
13	2105 HART			0.00000	0.00000	
14	2105 HART (Oroville Solar)			0.00000	0.00000	
	Total					

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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	2113 FITZJARRELL PRISTINE SUN			0.00000	0.00000	
2	2125 JARVIS PRISTINE SUN			0.00000	0.00000	
3	2127 HARRIS			0.00000	0.00000	
4	2154 FOOTE			0.00000	0.00000	
5	2154 FOOTE (Oroville Solar)			0.00000	0.00000	
6	2158 STROING PRISTINE SUN			0.00000	0.00000	
7	2179 SMOTHERMAN			0.00000	0.00000	
8	2184 GRUBER			0.00000	0.00000	
9	2184 GRUBER (ENERPARC)			0.00000	0.00000	
10	2192 RAMIREZ			0.00000	0.00000	
11	2192 RAMIREZ (Oroville Solar)			0.00000	0.00000	
12	3 PHASES RA - BU			0.00000	0.00000	
13	3 PHASES RENEWABLES			0.00000	0.00000	
14	ABEC #2 LLC			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	ABEC #3 LLC			0.00000	0.00000	
2	ABEC #4 LLC			0.00000	0.00000	
3	ABEC 2			0.00000	0.00000	
4	ABEC 3			0.00000	0.00000	
5	ABEC 4			0.00000	0.00000	
6	ABEC BIDART OLD RIVER			0.00000	0.00000	
7	ABEC BIDART STOCKDALE			0.00000	0.00000	
8	ABEC BIDART-STOCKDALE LLC			0.00000	0.00000	
9	AGUA CALIENTE SOLAR			0.00000	0.00000	
10	AGUA CALIENTE SOLAR, LLC			0.00000	0.00000	
11	ALAMO SOLAR			0.00000	0.00000	
12	ALAMO SOLAR RAM 2			0.00000	0.00000	
13	ALGONQUIN SANGER - BU			0.00000	0.00000	
14	ALGONQUIN SKIC 20 SOLAR			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	ALPAUGH 50 LLC			0.00000	0.00000	
2	ALPAUGH NORTH LLC			0.00000	0.00000	
3	ANGELS POWERHOUSE			0.00000	0.00000	
4	ANGELS POWERHOUSE (UTICA)			0.00000	0.00000	
5	Annual True-up GTSRBA			0.00000	0.00000	
6	APEX 646-460			0.00000	0.00000	
7	ARBUCKLE MOUNTAIN HYDRO			0.00000	0.00000	
8	ARLINGTON WIND POWER PROJECT			0.00000	0.00000	
9	ARLINGTON WIND RATTLESNAKE ROAD			0.00000	0.00000	
10	ASPIRATION SOLAR G			0.00000	0.00000	
11	ATWELL ISLAND			0.00000	0.00000	
12	AV SOLAR RANCH ONE			0.00000	0.00000	
13	Avangrid Renewables, LLC - Energy and			0.00000	0.00000	
14	AVENAL SOLAR PROJECT A			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	AVENAL SOLAR PROJECT B			0.00000	0.00000	
2	BADGER CREEK LIMITED			0.00000	0.00000	
3	BADGER CREEK LIMITED CHP RFO-2			0.00000	0.00000	
4	BAKER CREEK HYDROELECTRIC			0.00000	0.00000	
5	BAKERSFIELD 111 LLC			0.00000	0.00000	
6	BAKERSFIELD INDUSTRIAL 1			0.00000	0.00000	
7	BAKERSFIELD PV 1			0.00000	0.00000	
8	BAYSHORE SOLAR A			0.00000	0.00000	
9	BAYSHORE SOLAR B			0.00000	0.00000	
10	BAYSHORE SOLAR C			0.00000	0.00000	
11	BEAR CREEK SOLAR LLC			0.00000	0.00000	
12	BEAR MOUNTAIN LIMITED			0.00000	0.00000	
13	BEAR MOUNTAIN LIMITED (2013 CHP			0.00000	0.00000	
14	BIG CREEK WATER WORKS			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	BLACKSPRING RIDGE 1A			0.00000	0.00000	
2	BLACKSPRING RIDGE 1B			0.00000	0.00000	
3	BLACKWELL SOLAR			0.00000	0.00000	
4	BLAKE'S LANDING FARMS INC			0.00000	0.00000	
5	BNPP_FCM_BU			0.00000	0.00000	
6	BP ENERGY CO. - BU			0.00000	0.00000	
7	BROWNS VALLEY IRRIGATION DIST			0.00000	0.00000	
8	BUCKEYE HYDROELECTRIC PROJECT			0.00000	0.00000	
9	Burney Forest - BIOMASS			0.00000	0.00000	
10	CALAVERAS PUBLIC UTILI. DIST. 1			0.00000	0.00000	
11	CALAVERAS PUBLIC UTILI. DIST. 2			0.00000	0.00000	
12	CALAVERAS PUBLIC UTILI. DIST. 3			0.00000	0.00000	
13	CALIFORNIA FLATS SOLAR 150			0.00000	0.00000	
14	California Flats Solar Project			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CALPINE ENERGY - AGNEWS, INC			0.00000	0.00000	
2	CALPINE ENERGY SERVICES REC 2019			0.00000	0.00000	
3	Calpine Energy Services, LP			0.00000	0.00000	
4	CALPINE GEYSERS (200/425 MW)			0.00000	0.00000	
5	CALPINE LOS ESTEROS			0.00000	0.00000	
6	CALPINE PEAKERS			0.00000	0.00000	
7	CALPINE RETAINED ASSET			0.00000	0.00000	
8	CALPINE RUSSELL CITY			0.00000	0.00000	
9	CALRENEW CLEANTECH			0.00000	0.00000	
10	CALRENEW-1 LLC			0.00000	0.00000	
11	CAMS DOUBLE C LIMITED			0.00000	0.00000	
12	CAMS HIGH SIERRA LIMITED			0.00000	0.00000	
13	CAMS KERN FRONT LIMITED			0.00000	0.00000	
14	CAMS-DOUBLE C LIMITED			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CAMS-HIGH SIERRA LIMITED			0.00000	0.00000	
2	CAMS-KERN FRONT LIMITED			0.00000	0.00000	
3	CASTOR SOLAR PROJECT			0.00000	0.00000	
4	CCCE - BU			0.00000	0.00000	
5	CED CORCORAN SOLAR 3 LLC			0.00000	0.00000	
6	CED WHITE RIVER SOLAR 2, LLC			0.00000	0.00000	
7	CED WHITE RIVER SOLAR, LLC			0.00000	0.00000	
8	CEDAR FLAT			0.00000	0.00000	
9	CEDAR FLAT (Hudson Power)			0.00000	0.00000	
10	CENTRAL COAST COMMUNITY ENERGY			0.00000	0.00000	
11	CHALK CLIFF LIMITED			0.00000	0.00000	
12	CHEVRON NATURAL - BU			0.00000	0.00000	
13	CHOICE NATURAL GAS - BU			0.00000	0.00000	
14	CID SOLAR LLC RAM 2			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CID SOLAR, LLC			0.00000	0.00000	
2	CITADEL ENERGY MARKETING LL - BU			0.00000	0.00000	
3	CITY OF SAN JOSE			0.00000	0.00000	
4	City of San Jos,			0.00000	0.00000	
5	CLEAN PWR ALLIANCE			0.00000	0.00000	
6	CLEANPOWERSF			0.00000	0.00000	
7	CLOVER FLAT LFG			0.00000	0.00000	
8	CLOVERDALE SOLAR 1 LLC			0.00000	0.00000	
9	COLUMBIA SOLAR ENERGY LLC			0.00000	0.00000	
10	COMMERCIAL ENERGY OF MT - BU			0.00000	0.00000	
11	CONOCOPHILLIPS CO. - BU			0.00000	0.00000	
12	COPPER MOUNTAIN 10			0.00000	0.00000	
13	COPPER MOUNTAIN 2 SEMPRA			0.00000	0.00000	
14	COPPER MOUNTAIN SOLAR 48			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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)	Average Monthly CP Demand (f)
1	CORAM BRODIE WIND			0.00000	0.00000	
2	CORCORAN SOLAR			0.00000	0.00000	
3	CRC MARKETING, INC. - BU			0.00000	0.00000	
4	CUYAMA SOLAR			0.00000	0.00000	
5	Delano Land 1			0.00000	0.00000	
6	DELANO PV 1 LLC			0.00000	0.00000	
7	DESERT CENTER SOLAR FARM			0.00000	0.00000	
8	DIGGER CREEK HYDRO			0.00000	0.00000	
9	Direct Energy			0.00000	0.00000	
10	DIRECT ENERGY - BU			0.00000	0.00000	
11	DTE POTRERO HILL ENERGY PRODCERS			0.00000	0.00000	
12	DTE STOCKTON			0.00000	0.00000	
13	DTE SUNSHINE GAS LANDFILL			0.00000	0.00000	
14	DTE WOODLAND BIOMASS			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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	EAGLE SOLAR			0.00000	0.00000	
2	East Bay CE			0.00000	0.00000	
3	EAST BAY COMM 2019 REC SALE 2			0.00000	0.00000	
4	EAST BAY COMMUNITY ENERGY - BU			0.00000	0.00000	
5	ECOS ENERGY KETTLEMAN SOLAR			0.00000	0.00000	
6	EDF TRADING - BU			0.00000	0.00000	
7	EIF PANOCHÉ (FIREBAUGH)			0.00000	0.00000	
8	EL DORADO IRRIGATION			0.00000	0.00000	
9	Electric Revenue RF&U ADJ - GTSRBA			0.00000	0.00000	
10	ENERPARC CA1 LLC			0.00000	0.00000	
11	ETIWANDA POWER PLANT			0.00000	0.00000	
12	EURUS (AVENAL PARK, LLC)			0.00000	0.00000	
13	EURUS (SAND DRAG, LLC)			0.00000	0.00000	
14	EURUS (SUN CITY PROJECT, LLC)			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	EURUS AVENAL PARK LLC			0.00000	0.00000	
2	EURUS SAND DRAG LLC			0.00000	0.00000	
3	EURUS SUN CITY LLC			0.00000	0.00000	
4	EVOL MKTS FTS LLC - FIN BRK -BU			0.00000	0.00000	
5	EVOLUTION MARKETS INC. - BU			0.00000	0.00000	
6	Exelon			0.00000	0.00000	
7	FALL RIVER MILLS A ACHOMAWI			0.00000	0.00000	
8	FALL RIVER MILLS B AHJUMAWI			0.00000	0.00000	
9	FRESH AIR ENERGY IV SONORA 1			0.00000	0.00000	
10	FRESNO SOLAR SOUTH			0.00000	0.00000	
11	FRESNO SOLAR WEST			0.00000	0.00000	
12	GAS TRANSPORT ASSOC WITH PANOCHÉ			0.00000	0.00000	
13	GAS TRANSPORT ASSOC. WITH MARSH			0.00000	0.00000	
14	GENESIS SOLAR, LLC			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	GEYSERS 50/250/425 MW			0.00000	0.00000	
2	GLOBAL AMPERSAND CHOWCHILLA			0.00000	0.00000	
3	GLOBAL AMPERSAND EL NIDO			0.00000	0.00000	
4	GOOSE VALLEY FARMING			0.00000	0.00000	
5	GRASSHOPPER FLAT			0.00000	0.00000	
6	GRASSHOPPER FLAT (EMMERSON) -			0.00000	0.00000	
7	GREEN LIGHT ENERGY SIRUIS SOLAR			0.00000	0.00000	
8	GREEN LIGHT MADERA 1			0.00000	0.00000	
9	GWF HANFORD			0.00000	0.00000	
10	GWF HENRIETTA			0.00000	0.00000	
11	GWF TRACY			0.00000	0.00000	
12	HALKIRK I WIND PROJECT			0.00000	0.00000	
13	HATCHET RIDGE WIND LLC			0.00000	0.00000	
14	HENRIETTA SOLAR			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	HETCH HETCHY - BU			0.00000	0.00000	
2	HIGH PLAIN RANCH II			0.00000	0.00000	
3	HIGH PLAINS RANCH II			0.00000	0.00000	
4	HIGH PLAINS RANCH III			0.00000	0.00000	
5	HOLLISTER SOLAR ECOS ENERGY			0.00000	0.00000	
6	IBERDROLA KLONDIKE (AKA PPM			0.00000	0.00000	
7	IBERDROLA RENEWABLES (AKA PPM			0.00000	0.00000	
8	ICAP - BU			0.00000	0.00000	
9	ICE - BU			0.00000	0.00000	
10	IMMODO LEMOORE			0.00000	0.00000	
11	IVANPAH UNIT 1			0.00000	0.00000	
12	IVANPAH UNIT 3			0.00000	0.00000	
13	JACKSON VALLEY IRRIGATION DIST			0.00000	0.00000	
14	KANSAS			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	KEKAWAKA CREEK (STS)			0.00000	0.00000	
2	KENT SOUTH - PV 2			0.00000	0.00000	
3	KERN RIVER COGEN			0.00000	0.00000	
4	KERN RIVER COGEN (KRCC)			0.00000	0.00000	
5	KINGSBURG 1 TULARE PV II LLC			0.00000	0.00000	
6	KINGSBURG 2 TULARE PV II LLC			0.00000	0.00000	
7	KINGSBURG 3 TULARE PV II LLC			0.00000	0.00000	
8	KLONDIKE III			0.00000	0.00000	
9	KLONDIKE III S&F			0.00000	0.00000	
10	LA JOYA DEL SOL 1			0.00000	0.00000	
11	LASSEN STATION			0.00000	0.00000	
12	LEMOORE PV 1, LLC			0.00000	0.00000	
13	LIVE OAK LIMITED			0.00000	0.00000	
14	LOST CREEK 1			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	LOST CREEK 2			0.00000	0.00000	
2	LOST HILLS SOLAR			0.00000	0.00000	
3	MACQUARIE FUTURES_FCM - BU			0.00000	0.00000	
4	MADERA CHOWCHILLA - SITE 1923			0.00000	0.00000	
5	MADERA CHOWCHILLA SITE 1174			0.00000	0.00000	
6	MADERA CHOWCHILLA SITE 1302			0.00000	0.00000	
7	MADERA CHOWCHILLA SITE 980			0.00000	0.00000	
8	MAMMOTH G1 (ORMAT) - RAM 2			0.00000	0.00000	
9	MAMMOTH G3 RAM 1			0.00000	0.00000	
10	MANTECA LAND 1			0.00000	0.00000	
11	MARIN CLEAN ENERGY			0.00000	0.00000	
12	MARIPOSA ENERGY LLC			0.00000	0.00000	
13	MARSH LANDING			0.00000	0.00000	
14	MARSH LANDING CGT			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MATTHEWS DAM HYDRO			0.00000	0.00000	
2	MCE			0.00000	0.00000	
3	MCFADDEN HYDRO FACILITY			0.00000	0.00000	
4	MCKITTRICK LIMITED			0.00000	0.00000	
5	MERCED 1			0.00000	0.00000	
6	MERCED SOLAR ECOS ENERGY			0.00000	0.00000	
7	MESQUITE SOLAR			0.00000	0.00000	
8	MIDWAY SOLAR FARM 1			0.00000	0.00000	
9	MIDWAY SOLAR FARM 2			0.00000	0.00000	
10	MIDWAY SUNSET COGENERATION			0.00000	0.00000	
11	MIECO INC. - BU			0.00000	0.00000	
12	MILL SULPHUR CREEK PROJECT			0.00000	0.00000	
13	MISSION SOLAR ECOS ENERGY			0.00000	0.00000	
14	MOJAVE SOLAR			0.00000	0.00000	
	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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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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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)	Average Monthly CP Demand (f)
1	MONTEREY BAY COMM PWR AUTHORITY			0.00000	0.00000	
2	Monterey Bay Community Power - Carbon			0.00000	0.00000	
3	MORELOS SOLAR LLC - RAM 3			0.00000	0.00000	
4	MORGAN STANLEY			0.00000	0.00000	
5	MT. POSO (RED HAWK)			0.00000	0.00000	
6	NEVP - NORTH DELIVERY - BU			0.00000	0.00000	
7	NEXTERA DIABLO WINDS			0.00000	0.00000	
8	NEXTERA MONTEZUMA WIND			0.00000	0.00000	
9	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
10	NEXTERA MONTEZUMA WIND II			0.00000	0.00000	
11	NGX USD - BU			0.00000	0.00000	
12	NGX_ICE - BU			0.00000	0.00000	
13	NICKEL 1 NLH1 SOLAR			0.00000	0.00000	
14	NID CHICAGO PARK			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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	NID DUTCH FLAT ROLLINS BOWMAN			0.00000	0.00000	
2	NID NORTH COMBIE FIT			0.00000	0.00000	
3	NID SCOTTS FLAT			0.00000	0.00000	
4	NID SOUTH COMBIE FIT			0.00000	0.00000	
5	NID-CHICAGO PARK			0.00000	0.00000	
6	NID-DUTCH FLATS, ROLLINS, BOWMAN			0.00000	0.00000	
7	NORTH SKY RIVER ENERGY CENTER			0.00000	0.00000	
8	NORTH STAR SOLAR			0.00000	0.00000	
9	NRG ALPINE SOLAR			0.00000	0.00000	
10	NRG SOLAR KANSAS SOUTH			0.00000	0.00000	
11	OAKLEY EXECUTIVE LLC			0.00000	0.00000	
12	OLD RIVER ONE LLC - RAM 3			0.00000	0.00000	
13	OPEN SKY DAIRY DIGESTER #2			0.00000	0.00000	
14	OPEN SKY DIARY DIGESTER #2 - NEW			0.00000	0.00000	
	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)	Average Monthly CP Demand (f)
1	ORION SOLAR I LLC			0.00000	0.00000	
2	OROVILLE COGEN			0.00000	0.00000	
3	OROVILLE COGEN TOLLING			0.00000	0.00000	
4	ORTIGALITA POWER COMPANY LLC			0.00000	0.00000	
5	PACIFIC SUMMIT - BU			0.00000	0.00000	
6	PACIFICORP - BU			0.00000	0.00000	
7	PANOCHÉ ENERGY CGT			0.00000	0.00000	
8	PCWA LINCOLN HYDRO			0.00000	0.00000	
9	PEACOCK SOLAR PROJ - GREEN LIGHT			0.00000	0.00000	
10	PEACOCK SOLAR PROJECT			0.00000	0.00000	
11	Peninsula CEA			0.00000	0.00000	
12	PENINSULA CLEAN ENERGY 2022			0.00000	0.00000	
13	Peninsula Clean Energy Authority - Ene			0.00000	0.00000	
14	PILOT POWER - BU			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PIONEER COMM ENERGY - BU			0.00000	0.00000	
2	PORTAL RIDGE SOLAR C PROJECT			0.00000	0.00000	
3	POTRERO HILLS ENERGY LLC			0.00000	0.00000	
4	POWEREX CORP			0.00000	0.00000	
5	POWEREX SHAPING FIRING			0.00000	0.00000	
6	PUTAH CREEK SOLAR FARMS			0.00000	0.00000	
7	RE ASTORIA			0.00000	0.00000	
8	RE TRANQUILLITY 8 AMARILLO			0.00000	0.00000	
9	REDWOOD 4 SOLAR FARM			0.00000	0.00000	
10	RISING TREE WIND FARM II LLC			0.00000	0.00000	
11	RISING TREE WIND FARM II LLC - RAM 4			0.00000	0.00000	
12	ROCK CREEK HYDRO			0.00000	0.00000	
13	SACRAMENTO MUNICIPAL UTILITY DIS			0.00000	0.00000	
14	SALMON CREEK HYDROELECTRIC			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SAN JOSE CLEAN ENERGY - BU			0.00000	0.00000	
2	SAN JOSE WATER COX AVE HYDRO			0.00000	0.00000	
3	SAN LUIS BYPASS			0.00000	0.00000	
4	SAN LUIS OBISPO AD			0.00000	0.00000	
5	SAN LUIS OBISPO AD - NEW			0.00000	0.00000	
6	SANTA MARIA II LFG POWER			0.00000	0.00000	
7	SEMPRA GAS & POWER - BU			0.00000	0.00000	
8	SEMPRA MESQUITE SOLAR			0.00000	0.00000	
9	SFWP SLY CREEK KELLY RIDGE			0.00000	0.00000	
10	SFWP WOODLEAF FORBESTOWN			0.00000	0.00000	
11	SHAFTER SOLAR LLC			0.00000	0.00000	
12	SHAFTER SOLAR LLC RAM 3			0.00000	0.00000	
13	Shell Energy			0.00000	0.00000	
14	SHELL ENERGY 2019 REC SALE 1			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SHELL ENERGY 2019 REC SALE 2			0.00000	0.00000	
2	SHELL ENERGY 2019 REC SALE 3			0.00000	0.00000	
3	SHILOH I WIND			0.00000	0.00000	
4	SHILOH II WIND (AKA ENXCO)			0.00000	0.00000	
5	SHILOH II WIND PROJECT AR			0.00000	0.00000	
6	SHILOH IV			0.00000	0.00000	
7	SIERRA GREEN ENERGY LLC			0.00000	0.00000	
8	SIERRA PACIFIC INDUSTRIES			0.00000	0.00000	
9	SIERRA PACIFIC POWER TSA			0.00000	0.00000	
10	SILICON VALLEY CLEAN ENERGY - BU			0.00000	0.00000	
11	SILVER SPRINGS			0.00000	0.00000	
12	Silver Springs (Mega)			0.00000	0.00000	
13	SMUD - BU			0.00000	0.00000	
14	SO CAL EDISON - BU			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SOLAR PARTNERS II (IVANPAH UNIT 1)			0.00000	0.00000	
2	SOLAR PARTNERS VIII (IVANPAH UNIT 3)			0.00000	0.00000	
3	SONOMA POWER - BU			0.00000	0.00000	
4	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
5	SOUTH FEATHER WATER AND POWER			0.00000	0.00000	
6	SOUTH SUTTER WATER DISTRICT (expired)			0.00000	0.00000	
7	SR SOLIS ORO - PROJECT A			0.00000	0.00000	
8	SR SOLIS ORO - PROJECT B			0.00000	0.00000	
9	STARWOOD POWER MIDWAY, LLC			0.00000	0.00000	
10	Still Water (NEW)			0.00000	0.00000	
11	STILL WATER POWER			0.00000	0.00000	
12	SUMMER WHEAT SAN JOAQUIN 1A			0.00000	0.00000	
13	SUN HARVEST SOLAR NDP1			0.00000	0.00000	
14	SUNRAY 2			0.00000	0.00000	
	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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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SUNSHINE GAS LANDFILL			0.00000	0.00000	
2	SUTTERS MILL HYDROELECTRIC PLANT			0.00000	0.00000	
3	TENASKA MKTG - BU			0.00000	0.00000	
4	TENASKA POWER SERVICES - BU			0.00000	0.00000	
5	TESORO - MARTINEZ COGEN LP			0.00000	0.00000	
6	TESORO REFINING & MARKETING LLC			0.00000	0.00000	
7	THE ENERGY AUTHORITY - BU			0.00000	0.00000	
8	THREE FORKS			0.00000	0.00000	
9	TOPAZ SOLAR FARM			0.00000	0.00000	
10	TORO SLO LANDFILL			0.00000	0.00000	
11	TRANSALTA - BU			0.00000	0.00000	
12	TULLETT PREBON AMERICAS COR - BU			0.00000	0.00000	
13	TUNNEL HILL HYDRO			0.00000	0.00000	
14	TWIN VALLEY HYDRO			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	VANTAGE WIND ENERGY LLC			0.00000	0.00000	
2	VASCO WINDS (NEXTERA)			0.00000	0.00000	
3	VECINO VINEYARDS LLC			0.00000	0.00000	
4	VERWEY HANFORD DAIRY 2 - NEW			0.00000	0.00000	
5	VERWEY HANFORD DAIRY 3 - NEW			0.00000	0.00000	
6	VERWEY MADERA DAIRY DIGESTER 2			0.00000	0.00000	
7	VERWEY MADERA DAIRY DIGESTER 2			0.00000	0.00000	
8	VERWEY-HANFORD DAIRY 2			0.00000	0.00000	
9	VERWEY-HANFORD DAIRY 3			0.00000	0.00000	
10	VINTNER SOLAR LLC			0.00000	0.00000	
11	WATER WHEEL RANCH			0.00000	0.00000	
12	WECC WREGIS FEES			0.00000	0.00000	
13	WEST ANTELOPE - RAM 1			0.00000	0.00000	
14	WESTERN ANTELOPE BLUE SKY			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	WESTERN ELECTRICITY COORDINATING			0.00000	0.00000	
2	WESTLANDS SOLAR FARMS LLC			0.00000	0.00000	
3	WESTSIDE SOLAR LLC			0.00000	0.00000	
4	WHEELABRATOR SHASTA BIOMASS			0.00000	0.00000	
5	WHITE RIVER SOLAR 2			0.00000	0.00000	
6	WHITE RIVER SOLAR CED			0.00000	0.00000	
7	WIND RESOURCE 1 CALWIND RAM 1			0.00000	0.00000	
8	WIND RESOURCE 2 CALWIND RAM 2			0.00000	0.00000	
9	WINTER WHEAT SAN JOAQUIN 1B			0.00000	0.00000	
10	WOLFSEN BYPASS (CCID)			0.00000	0.00000	
11	WOODLAND BIOMASS			0.00000	0.00000	
12	WOODMERE SOLAR FARM			0.00000	0.00000	
13	WOODMERE SOLAR RAM 4			0.00000	0.00000	
14	YCWA MINI HYDRO			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	YOLO COUNTY GRASSLAND 3			0.00000	0.00000	
2	YOLO COUNTY GRASSLAND 4			0.00000	0.00000	
3	ZERO WASTE ENERGY			0.00000	0.00000	
4	MISC. CONTRACT DATA			0.00000	0.00000	
5						
6	Pipeline charges			0.00000	0.00000	
7	RUBY PIPELINE			0.00000	0.00000	
8	WILLIAMS FIELD SERVICES -			0.00000	0.00000	
9	SOUTHERN CA GAS - BU			0.00000	0.00000	
10	Gas Transmission Northwest			0.00000	0.00000	
11						
12	Other charges			0.00000	0.00000	
13	Irrigation districts			0.00000	0.00000	
14	Liberty Utilities			0.00000	0.00000	
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ISO charges for storage cost			0.00000	0.00000	
2	ISO charges (net of storage cost but			0.00000	0.00000	
3	Gas purchases, storage cost & forex			0.00000	0.00000	
4	CARB fees			0.00000	0.00000	
5	Consultancy fees			0.00000	0.00000	
6	Gas Hedges & brokers fees			0.00000	0.00000	
7	RECS from customers			0.00000	0.00000	
8	RA MPB True-up to RA Adder and Revenue			0.00000	0.00000	
9						
10	Rounding in column I					
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
							2
196			797	6,606		7,403	3
571			3,636	18,422		22,058	4
52			63	1,763		1,826	5
							6
				2		2	7
8,918			126,740	214,786		341,526	8
66			118	1,616		1,734	9
2			3	57		60	10
150			1,487	6,311		7,798	11
426			1,642	11,874		13,516	12
							13
2,690			21,306	106,920		128,226	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
269			2,119	10,593		12,712	1
							2
8,882			51,852	245,088		296,940	3
64			374	-637		-263	4
18,166			561,312	718,013		1,279,325	5
762			5,038	23,961		28,999	6
273			831	8,949		9,780	7
							8
2,846			23,847	56,038		79,885	9
							10
				3		3	11
248			2,132	8,925		11,057	12
							13
43			468	1,565		2,033	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
726			7,702	22,203		29,905	1
							2
2,356			48,562	73,597		122,159	3
744			35	28,871		28,906	4
606			19,494	19,021		38,515	5
20,139				607,223		607,223	6
9				-372		-372	7
							8
1,344,212			53,811,096	45,303,715		99,114,811	9
25,503			122,996	848,234		971,230	10
7,039			26,029	202,109		228,138	11
							12
86			299	2,999		3,298	13
6				155		155	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
195			667	7,067		7,734	1
4,845			9,298	166,203		175,501	2
16			2	550		552	3
7,503			20,738	262,808		283,546	4
1				23		23	5
55			121	1,930		2,051	6
34			32	1,251		1,283	7
15			59	570		629	8
48			103	1,740		1,843	9
				1		1	10
							11
-5,521				-1,088		-1,088	12
37,719			10,485,766	1,269,052		11,754,818	13
							14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
926			6,212	33,900		40,112	1
			798,353			798,353	2
12,393			8,007,979	156,811		8,164,790	3
29,429				1,427,303		1,427,303	4
16,198			114,299	540,894		655,193	5
20,703			139,695	707,692		847,387	6
6,568			39,645	170,894		210,539	7
14,208			173,709	453,219		626,928	8
133,636			1,491,553	4,507,766		5,999,319	9
96,954			858,458	3,140,788		3,999,246	10
8,735			56,778	330,664		387,442	11
43,578			308,678	1,469,646		1,778,324	12
6,697			36,185	218,491		254,676	13
19,690			141,182	650,587		791,769	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
							2
604				85,782		85,782	3
2,412				331,993		331,993	4
1,075				146,977		146,977	5
534				75,186		75,186	6
2,537			-818	351,433		350,615	7
1,239				178,032		178,032	8
1,414				202,910		202,910	9
3,693				550,038		550,038	10
2,035				298,050		298,050	11
726				98,978		98,978	12
1,099				72,957		72,957	13
48				1,577		1,577	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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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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)	
609				82,225		82,225	1
313				45,361		45,361	2
2,427				256,990		256,990	3
580				79,788		79,788	4
24				-9,537		-9,537	5
1,053				145,649		145,649	6
522				75,407		75,407	7
3,447				322,581		322,581	8
151				5,457		5,457	9
659				82,852		82,852	10
				-2,449		-2,449	11
			-164,784			-164,784	12
-50,000				-812,500		-812,500	13
726				-26,970		-26,970	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
427				-3,476		-3,476	1
589				-11,983		-11,983	2
8,381				1,520,278		1,520,278	3
6,704				1,292,307		1,292,307	4
7,650				1,411,831		1,411,831	5
14,858				1,970,444		1,970,444	6
1,094				195,225		195,225	7
62				488		488	8
718,309			-22,500	125,393,031		125,370,531	9
46,593				729,655		729,655	10
1,612				57,686		57,686	11
41,081			-3,500	3,523,222		3,519,722	12
			1,478,440			1,478,440	13
48,480				4,052,695		4,052,695	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
123,402				21,560,663		21,560,663	1
46,358				7,714,100		7,714,100	2
5,596				495,922		495,922	3
514				-18,153		-18,153	4
				-101,870		-101,870	5
1,821				198,579		198,579	6
			-427			-427	7
19,541				1,192,029		1,192,029	8
251,291				25,297,757		25,297,757	9
22,146				1,431,231		1,431,231	10
34,289				5,630,067		5,630,067	11
598,584				87,967,714		87,967,714	12
							13
14,162				1,091,288		1,091,288	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
13,627				1,044,564		1,044,564	1
18,615			3,891,874	440,044		4,331,918	2
308				-35,793		-35,793	3
2,200			-2,509	196,178		193,669	4
3,408			-3,000	427,882		424,882	5
2,367				197,151		197,151	6
10,006				695,061		695,061	7
54,509				3,039,265		3,039,265	8
51,093				2,870,485		2,870,485	9
50,906				2,870,289		2,870,289	10
4,037				577,962		577,962	11
41,877			3,891,874	838,256		4,730,130	12
1,282				-21,035		-21,035	13
2,963				295,892		295,892	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
				19,601,937		19,601,937	1
				20,955,000		20,955,000	2
32,522				3,236,506		3,236,506	3
176				7,944		7,944	4
					10,985	10,985	5
					18	18	6
1,616				139,609		139,609	7
1,314				122,471		122,471	8
231,980				23,410,300	-14,500	23,395,800	9
299				47,343		47,343	10
276				12,662		12,662	11
182				18,146		18,146	12
364,717				27,230,763		27,230,763	13
19,361				316,886		316,886	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
13,398			4,366,615	300,113		4,666,728	1
-125,000				-2,250,000		-2,250,000	2
			138,750			138,750	3
180,250				4,494,011		4,494,011	4
287,971			67,414,776	6,207,634		73,622,410	5
99,546			32,723,614	3,828,900		36,552,514	6
				12,365		12,365	7
1,159,603			139,964,688	18,178,193		158,142,881	8
9,072				2,045,012		2,045,012	9
615				31,279		31,279	10
21,679			5,124,730	481,085	260,077	5,865,892	11
21,885			5,124,730	486,828	283,105	5,894,663	12
18,619			5,042,466	423,904	265,836	5,732,206	13
			-456,840	-16,771	-25,000	-498,611	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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		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)	
			-456,840	-18,796	-25,000	-500,636	1
			-456,840	-14,542	-25,000	-496,382	2
3,142			-4,500	400,675		396,175	3
			-862,781			-862,781	4
47,959				2,351,764		2,351,764	5
2,239				33,434		33,434	6
2,378				84,941		84,941	7
613				54,014		54,014	8
				-10,184		-10,184	9
-407,841				-6,631,488		-6,631,488	10
12,570			3,888,786	327,417		4,216,203	11
					6	6	12
					3,678	3,678	13
47,278				5,215,152		5,215,152	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
2,118				40,422		40,422	1
					-4	-4	2
-510,000				-9,440,000		-9,440,000	3
				190,000		190,000	4
-1,150,000			136,299	-18,853,000		-18,716,701	5
			-1,898,056			-1,898,056	6
5,319				457,796		457,796	7
1,975			-17,500	292,831		275,331	8
33,899				3,207,588		3,207,588	9
			534,700			534,700	10
155,152				-1,038,190	12	-1,038,178	11
22,463				3,036,867		3,036,867	12
391,417				49,179,077		49,179,077	13
105,728				16,410,125		16,410,125	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
259,832			-26,000	28,227,809		28,201,809	1
50,858				7,918,725		7,918,725	2
							3
97,304				9,758,548		9,758,548	4
82				224		224	5
1,769				157,668	-3,314	154,354	6
682,736			-7,000	112,434,610		112,427,610	7
2,681				215,263		215,263	8
				1,380,800		1,380,800	9
-400,000			-1,037,597	-6,748,000		-7,785,597	10
5,375				-8,166		-8,166	11
412,770			-2,813,408	49,646,136		46,832,728	12
11,276				41,904		41,904	13
				-1,268,319		-1,268,319	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
8,240				369,999		369,999	1
				1,850,000		1,850,000	2
-1,100,000				-21,100,000		-21,100,000	3
			-3,686,711			-3,686,711	4
2,653			-1,500	334,976		333,476	5
			-94,900			-94,900	6
616,494			51,151,454	3,951,834		55,103,288	7
67,618				7,322,855		7,322,855	8
				576		576	9
3,291			-18,000	460,238		442,238	10
							11
716				139,526		139,526	12
2,245				437,500		437,500	13
2,367				461,084		461,084	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
11,064				2,777,578		2,777,578	1
35,332				8,880,336		8,880,336	2
37,108				9,365,695		9,365,695	3
					14,573	14,573	4
					4,845	4,845	5
-1,220,131			6,669	-20,200,000		-20,193,331	6
3,872				556,450		556,450	7
3,169				469,884		469,884	8
3,743				405,412		405,412	9
3,309				419,773		419,773	10
3,308				416,202		416,202	11
							12
							13
619,268			-10,000	131,060,423		131,050,423	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
2,136,029			12,425,000	158,895,115		171,320,115	1
72,949				7,316,719		7,316,719	2
61,122				6,870,083		6,870,083	3
191				17,338		17,338	4
1,162				99,543		99,543	5
				-8,006		-8,006	6
2,114				219,405		219,405	7
2,858			-2,639	155,726		153,087	8
18,817			8,360,536	813,473		9,174,009	9
30,356			8,305,211	767,577		9,072,788	10
861,061			67,254,850	11,410,816		78,665,666	11
				20,016,892		20,016,892	12
305,202				31,737,004		31,737,004	13
250,671				25,091,849		25,091,849	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
			-258,746			-258,746	1
535,949				74,179,806		74,179,806	2
28,747				1,004,749		1,004,749	3
108,188			-1,500	15,263,678		15,262,178	4
3,948				506,352		506,352	5
12,621				199,320		199,320	6
				468,802		468,802	7
					5,479	5,479	8
					129,417	129,417	9
85				-4,016		-4,016	10
280,913				46,161,812		46,161,812	11
283,875				47,384,805		47,384,805	12
328				32,979		32,979	13
46,844				4,569,944		4,569,944	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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

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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)	
				16		16	1
49,881				4,189,504		4,189,504	2
461,653			17,925,660	15,859,913		33,785,573	3
1,023			-164,677	-28,810		-193,487	4
2,645				352,335		352,335	5
2,937				384,924		384,924	6
1,463				143,871		143,871	7
234,248				13,703,492		13,703,492	8
				5,127,314		5,127,314	9
1,494			-26,000	187,648		161,648	10
879				76,796		76,796	11
1,356				165,518		165,518	12
21,376			3,903,454	425,789		4,329,243	13
520				49,195		49,195	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
235				16,504		16,504	1
54,052				5,375,247		5,375,247	2
					-2,982,050	-2,982,050	3
579				52,921		52,921	4
775				70,435		70,435	5
449				41,004		41,004	6
2,085			-561	191,035		190,474	7
63,072				5,555,247		5,555,247	8
112,831			-10,000	11,062,473		11,052,473	9
1,959				172,116		172,116	10
-500,000			-1,724,000	-9,278,000		-11,002,000	11
115,597			29,043,647	1,480,260		30,523,907	12
278,759			117,276,977	6,528,980		123,805,957	13
				16,845		16,845	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,329				278,310		278,310	1
				5,628,000		5,628,000	2
143				7,454		7,454	3
16,097			3,903,454	395,067		4,298,521	4
6,937				387,932		387,932	5
3,968				519,883		519,883	6
25,032				226,013		226,013	7
40,212				2,360,752		2,360,752	8
8,295				483,490		483,490	9
610,011			12,250,221	-1,287,652		10,962,569	10
							11
983				73,713		73,713	12
4,105			-17,000	532,059		515,059	13
566,756			-1,000	112,447,274		112,446,274	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
-1,177,150			84,510	-7,350,263	-73,901	-7,339,654	1
							2
36,803				3,242,097		3,242,097	3
				786,495		786,495	4
313,219			-1,500	39,319,168		39,317,668	5
					8,664	8,664	6
57,534				3,069,205		3,069,205	7
92,829				8,970,222		8,970,222	8
206,557				21,068,861		21,068,861	9
6,469				-117,202		-117,202	10
					158,892	158,892	11
					17,052	17,052	12
2,536			-1,111	331,936		330,825	13
85,209				10,446,771		10,446,771	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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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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)	
78,960				12,695,916		12,695,916	1
1,315				135,953		135,953	2
985				70,650		70,650	3
2,422				123,880		123,880	4
3,716				29,884		29,884	5
3,092				33,120		33,120	6
449,476				37,466,987		37,466,987	7
148,203				19,076,850		19,076,850	8
163,641				22,880,131		22,880,131	9
50,088				4,927,527		4,927,527	10
2,238			-3,500	313,766		310,266	11
49,103				3,963,826		3,963,826	12
5,506				1,048,700		1,048,700	13
				-78,604		-78,604	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
27,279				3,415,871		3,415,871	1
			-103,329			-103,329	2
201			906,533	56,247		962,780	3
							4
							5
					-62	-62	6
				172,869		172,869	7
984				98,909		98,909	8
127				5,611		5,611	9
1,748				234,274		234,274	10
-250,000			-1,763,236	-3,450,000		-5,213,236	11
-283,413				-6,833,152		-6,833,152	12
							13
			-320,100			-320,100	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
							1
30,056				1,881,255		1,881,255	2
63,529				7,907,921		7,907,921	3
-275,000				-4,727,750		-4,727,750	4
				9,625,197		9,625,197	5
5,032				534,873		534,873	6
298,677				19,404,349		19,404,349	7
54,774				3,592,547		3,592,547	8
51,730				3,167,274		3,167,274	9
52,701				3,190,517		3,190,517	10
2,754				25,960		25,960	11
556				46,738		46,738	12
-237,000				-3,723,270		-3,723,270	13
1,705				129,203		129,203	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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)	
			400,706			400,706	1
							2
540				56,142		56,142	3
1,765				207,531		207,531	4
112				12,922		12,922	5
6,257				581,002		581,002	6
172,800							7
413,569			24	66,675,362		66,675,386	8
59,965			1,906,580	2,176,332	-449,169	3,633,743	9
187,933			2,792,593	7,020,825		9,813,418	10
2,492				41,869		41,869	11
49,386				4,696,207		4,696,207	12
			-863,203	5,250,000		4,386,797	13
-100,000				-1,500,000		-1,500,000	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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.
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)	
-200,000				-3,000,000		-3,000,000	1
-800,000				-14,250,000		-14,250,000	2
204,273				11,248,718		11,248,718	3
24,403				-122,508		-122,508	4
650,603			-159,000	64,589,757		64,430,757	5
287,350			-67,000	24,909,726		24,842,726	6
147				17,557		17,557	7
433,361			502,615	38,153,174		38,655,789	8
					32,922	32,922	9
-600,000			-2,687,510	-9,900,000		-12,587,510	10
1,721				152,854		152,854	11
123				-1,645		-1,645	12
			-592,450		3	-592,447	13
			897,000			897,000	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
9,912				-637,892		-637,892	1
12,746				-907,095		-907,095	2
			-709,937			-709,937	3
5,471			178,735	-320,779		-142,044	4
15,673			232,716	-947,485		-714,769	5
				14,200		14,200	6
26,431				1,312,165		1,312,165	7
26,025				1,295,051		1,295,051	8
32,490			13,755,636	460,494		14,216,130	9
555				112,402		112,402	10
2,380				104,914		104,914	11
41,785			-500	2,181,083		2,180,583	12
2,739				242,847		242,847	13
61,129				3,777,815		3,777,815	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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)	
140,819				16,968,715		16,968,715	1
408				31,084		31,084	2
							3
			570,000			570,000	4
26,063			-77,323	966,156		888,833	5
288,667			2,524,802	12,422,812	-16,500	14,931,114	6
			-203,620			-203,620	7
4,556				375,216		375,216	8
1,348,224				210,095,537		210,095,537	9
11,486				1,178,929		1,178,929	10
				-92,004		-92,004	11
					2,685	2,685	12
2,247				212,377		212,377	13
1,230				145,646		145,646	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
324,588				30,267,814		30,267,814	1
235,193				24,506,702		24,506,702	2
							3
302				-24,392		-24,392	4
264				-34,438		-34,438	5
3,807				826,391		826,391	6
192				-38,425		-38,425	7
6,032				1,239,688		1,239,688	8
5,800				1,189,222		1,189,222	9
4,212				584,310		584,310	10
2,154				177,281		177,281	11
				80,899		80,899	12
60,576				5,101,916		5,101,916	13
47,680				3,375,415	-1,308,467	2,066,948	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
44,333				5,625,968		5,625,968	2
52,243				3,256,018		3,256,018	3
302,725				32,896,306	40,003	32,936,309	4
49,080				4,751,574		4,751,574	5
48,363				7,999,736		7,999,736	6
14,674				1,021,540		1,021,540	7
47,043				3,273,365		3,273,365	8
2,780				165,456	-6,000	159,456	9
2,587				257,781		257,781	10
46,280				4,315,106		4,315,106	11
1,681				20,866		20,866	12
35,735				2,619,990		2,619,990	13
1,282				104,600		104,600	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
2,447			-19,000	291,110		272,110	1
2,188				265,258		265,258	2
2,896			-53,480	314,873		261,393	3
				-2,222,885		-2,222,885	4
							5
							6
					11,175,809	11,175,809	7
					1,074	1,074	8
					12,685	12,685	9
					1	1	10
							11
							12
35,742					-254,259	-254,259	13
4,999					862,109	862,109	14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

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 monthly (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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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)	
					187,246	187,246	1
42,264,976					1,520,891,747	1,520,891,747	2
					83,782,990	83,782,990	3
					748,042	748,042	4
					614,184	614,184	5
					2,980,124	2,980,124	6
							7
					101,295	101,295	8
							9
					-7	-7	10
							11
							12
							13
							14
59,363,830			685,933,482	2,310,043,645	1,617,412,325	4,613,389,452	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 326.32 Line No.: 4 Column: a

Individual demand, energy, and other charges represented above are based upon the best available vendor invoice and estimate data at the time of filing. The total settlement difference of (\$2.2M) represents additional adjustments made throughout 2020, these additional adjustments tie back to information reported to the FERC (account 9555000).

The volumetric data by vendor is based on the invoiced and estimated trade data available at the time of filing.

Schedule Page: 326.33 Line No.: 10 Column: a

The original entries in column 1 were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1				
2	TRANSMISSION AGENCY OF			
3	NORTHERN CALIFORNIA (TANC)	Various	Various	LFP
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
 (Including transactions referred 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 (Substation 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)	
						1
						2
143	Midway	Various	233	553,931	543,456	3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			233	553,931	543,456	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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
				2
	2,787,769	87,000	2,874,769	3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	2,787,769	87,000	2,874,769	

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 3 Column: a

Other Charges represent booking estimate adjustments. In September 2003 the Utility changed billing methodology using energy as billing determinants rather than contract demand. The change was pursuant to the TO6 Settlement Agreement under FERC Docket No. ER03-666-000.

Transmission is provided under the Midway Transmission Service.

Recorded here are the Midway Transmission Service data for TANC members which include Modesto Irrigation District, Sacramento Municipal Utility District, City of Redding, and the Turlock Irrigation District.

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 Tariff (d)	Total Revenue (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	CALIFORNIA-OREGON							
2	TRANSMISSION PROJECT	OS					427,872	427,872
3	PACIFICORP	OS			94,264		37,742	132,006
4	SACRAMENTO MUNICIPAL							
5	UTILITY DISTRICT	OS						
6	WESTERN AREA POWER							
7	ADMINISTRATION	OS			2,280		98,000	100,280
8	CALIFORNIA-OREGON							
9	INTERTIE	OS					347,082	347,082
10	OTHER	OS						
11								
12								
13								
14								
15								
16								
	TOTAL				96,544		910,696	1,007,240

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

Represents payments for operations and maintenance costs.

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

Represents payments for lease of transmission capacity.

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

Represents payments for operations and maintenance costs.

Schedule Page: 332 Line No.: 7 Column: e

Represents payments for lease of transmission capacity.

Schedule Page: 332 Line No.: 9 Column: g

Represents payments for administrative costs of scheduling services provided by the California Independent Systems Operator (CAISO).

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	10
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6		
7	Clearing Account Adjustments	4,432,405
8	Intervenor Compensation	3,662,973
9	MCI-PG&E Exchange Rights	650,161
10	Bank Service Fees	15,928,580
11	Consulting Serv, Outside Attorney Fees and Contracts	-96,511
12	Intercompany Billing (Cost belongs in Acct 923)	3,085,859
13	Misc cash receipt (recovery of unclaimed funds)	-2,604
14	Write off from miscellaneous reconciliations	117,756
15	Other miscellaneous adjustments	12,309
16		
17		
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25		
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45		
46	TOTAL	27,790,938

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition 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			9,477,794		9,477,794
2	Steam Production Plant	27,147,305				27,147,305
3	Nuclear Production Plant	286,424,850			38,731,572	325,156,422
4	Hydraulic Production Plant-Conventional	114,172,158			4,752,000	118,924,158
5	Hydraulic Production Plant-Pumped Storage	25,851,996			3,389,004	29,241,000
6	Other Production Plant	54,354,959				54,354,959
7	Transmission Plant	414,273,966				414,273,966
8	Distribution Plant	1,329,297,368				1,329,297,368
9	Regional Transmission and Market Operation					
10	General Plant	47,101,619				47,101,619
11	Common Plant-Electric	163,109,222		136,067,709		299,176,931
12	TOTAL	2,461,733,443		145,545,503	46,872,576	2,654,151,522

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. The rates have been updated in accordance with 2020 GRC authorized rates.

The rates used to compute amortization charges for 'Intangible Plant – Electric' (Account 404) are as follows:
EIP30201 Intangible Plant: Franchise 2.40%; EIP30301 Intangible Plant: USBR 0%; EIP30303 Intangible Plant: Software 20.42%

The rates used to compute amortization charges for 'Common Plant – Electric' (Account 404) are as follows:
CMP30302 Intangible Plant: Software 17.36%; CMP30304 Intangible Plant: Software 9.01%

For FERC reporting purposes, common amortization expense is allocated to electric and gas amortization as common amortization expense is not reported on the FERC forms. The rate used to allocate the common amortization expense to electric is 64.70%.

Amortization of the Other Electric Plant (Account 405) - These amortization amounts represent the 2020 GRC authorized amounts to record for the recovery of the URG regulatory asset. In connection with the Chapter 11 Settlement Agreement, the CPUC authorized the Utility to recover \$1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities or recovery period, consistent with the period over which the related revenues are recognized.

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 Prod - Fossil						
13	310.02	4,801			2.38	SQ	
14	311	114,004	75.00		3.43	R1	17.90
15	312	282,647	50.00		3.62	R1	17.30
16	313						
17	314	257,634	40.00		3.55	R2.5	17.50
18	315	52,626	45.00		3.59	R2.5	17.90
19	316	28,349	40.00		3.70	S0.5	16.50
20	SUBTOTAL	740,061					
21							
22	Nuclear Prod - Diablo						
23	321	1,096,477	5.00			Life Span	4.30
24	322	3,596,678	5.00			Life Span	3.90
25	323	1,215,746	5.00			Life Span	3.70
26	324	870,127	5.00			Life Span	4.10
27	325	1,189,936	5.00			Life Span	4.20
28	SUBTOTAL	7,968,964					
29							
30	Hydraulic Production						
31	330	17,279			2.10	SQ	
32	331	540,755	80.00	-6.00	2.91	R2	12.60
33	332	2,204,008	120.00	-3.00	1.93	R2.5	16.40
34	333	1,081,479	71.00	-4.00	4.72	S0,SQ	12.80
35	334	315,250	65.00	-6.00	3.25	S0.5	15.20
36	335	134,986	55.00	-10.00	4.32	S0	12.90
37	336	97,987	80.00	-3.00	3.04	S1	15.50
38	SUBTOTAL	4,391,744					
39							
40	Other Production						
41	340.02	3,121			0.69	SQ	
42	341	211,569	59.00		3.66	R1,SQ	17.70
43	342	11,473	50.00		3.61	R1	17.40
44	343	228,651	40.00		3.55	R2.5	17.70
45	344	353,998	27.00		4.43	R2.5,SQ,R2	16.40
46	345	215,712	31.00		6.31	R2.5,S2.5,SQ	13.80
47	346	101,910	35.00		3.83	S0.5,SQ	16.60
48	SUBTOTAL	1,126,434					
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						
13	350.02	218,714	39.00		1.34	R4	21.60
14	352.00	523,565	70.00	-20.00	1.65	R3	57.70
15	353.00	7,341,814	2.00		0.07	R1.5	31.50
16	354	1,033,962	1.00	-2.00	0.13	R4	53.30
17	355	1,961,139	54.00	-75.00	3.16	R1.5	43.50
18	356	2,195,913	65.00	-75.00	2.74	R2	48.80
19	357	516,190	65.00		1.53	R4	51.80
20	358	288,767	55.00	-10.00	1.99	R3	40.70
21	359	132,270	60.00	-10.00	1.86	R1.5	49.80
22	SUBTOTAL	14,212,334					
23							
24	Transmission - Diablo						
25	352.01	4,981	5.00		-0.62		4.40
26	353.01	89,979	50.00	-39.00	6.51	R2	8.40
27	SUBTOTAL	94,960					
28							
29	Distribution						
30	360.02	121,789	40.00		2.18	SQ	17.30
31	361	329,238	70.00	-20.00	1.60	R3	50.90
32	362	3,901,000	46.00	-40.00	3.06	R1.5	33.20
33	363	34,560	15.00		6.45	R2,S3	7.30
34	364	6,139,824	44.00	-150.00	6.07	R2	29.90
35	365	5,371,284	46.00	-90.00	3.96	R2	31.30
36	366	3,303,829	65.00	-50.00	2.41	R4	44.40
37	367	5,359,204	50.00	-65.00	3.12	R3	32.40
38	368	4,514,370	32.00	-29.00	4.26	R2.5	20.20
39	369	3,763,523	51.00	-67.00	3.06	R2.5,R4	30.50
40	370	1,308,865	20.00	-20.00	6.86	R2	12.00
41	371	29,443	40.00	-3.00	0.24	S1,R4	5.50
42	372	895	25.00			L1	
43	373	268,830	29.00	-23.00	3.23	R1,S1.5,L0	9.60
44	SUBTOTAL	34,446,654					
45							
46	General Plant						
47	389.02	415	59.00		2.92	SQ	28.90
48	390	22,491	50.00	-10.00	1.58	R2	31.00
49	391.00	10,700	20.00		5.93	SQ	8.40
50	394	173,971	25.00		3.94	SQ	14.40

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	395	11,927	20.00		4.74	SQ	10.80
13	396						
14	397	519,375	15.00		6.89	SQ	10.10
15	398.00	34,109	20.00		6.85	SQ	16.70
16	SUBTOTAL	772,988					
17							
18	General Plant - Diablo						
19	391.01	4,508	5.00		12.25	Life Span	3.40
20	398.01	15,882	5.00		12.36	Life Span	4.80
21	SUBTOTAL	20,390					
22							
23	TOTAL	63,774,529					
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
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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	Annual fees paid for Diablo Canyon Power Plant				
2	in accordance with Part 171				
3	Docket 5000275	4,809,059		4,809,059	
4	Docket 5000323	4,809,059		4,809,059	
5					
6	Fees paid for Diablo Canyon Power Plant				
7	for inspection, license renewal, operator				
8	examination in accordance with Part 170				
9	Docket 5000275	1,065,719		1,065,719	
10	Docket 5000275	125,668		125,668	
11	Docket 5000323	1,023,956		1,023,956	
12	Docket 5000323	91,757		91,757	
13	General Accrual	120,378		120,378	
14	General Accrual	-64,913		-64,913	
15					
16	Annual fees paid for Humbolt Bay Power Plant				
17	in accordance with Part 171				
18	Docket 5000133	197,202		197,202	
19					
20	*All paid to US Nuclear Regulatory Commission				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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37					
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40					
41					
42					
43					
44					
45					
46	TOTAL	12,177,885		12,177,885	

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			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
	524	4,809,059					3
	524	4,809,059					4
							5
							6
							7
							8
	524	1,065,719					9
	930	125,668					10
	524	1,023,956					11
	930	91,757					12
	524	120,378					13
	930	-64,913					14
							15
							16
							17
	930	197,202					18
							19
							20
							21
							22
							23
							24
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							39
							40
							41
							42
							43
							44
							45
		12,177,885					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A2, A3	Electric Program Investment Charge
2		
3		
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6	A2, A3	Customer Energy Services -
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
 - (3) Research Support to Nuclear Power Groups
 - (4) Research Support to Others (Classify)
 - (5) Total Cost Incurred
3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
-20,998		408	13,850		1
		588	-76,578		2
		926	41,579		3
		930	151		4
					5
-8,617		408	15		6
		588	-8,678		7
		926	46		8
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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	310,125,433		
4	Transmission	119,863,290		
5	Regional Market			
6	Distribution	310,520,769		
7	Customer Accounts	113,350,231		
8	Customer Service and Informational	45,656,457		
9	Sales	943,217		
10	Administrative and General	326,474,133		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	1,226,933,530		
12	Maintenance			
13	Production	103,134,928		
14	Transmission	59,742,298		
15	Regional Market			
16	Distribution	192,128,641		
17	Administrative and General	388		
18	TOTAL Maintenance (Total of lines 13 thru 17)	355,006,255		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	413,260,361		
21	Transmission (Enter Total of lines 4 and 14)	179,605,588		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	502,649,410		
24	Customer Accounts (Transcribe from line 7)	113,350,231		
25	Customer Service and Informational (Transcribe from line 8)	45,656,457		
26	Sales (Transcribe from line 9)	943,217		
27	Administrative and General (Enter Total of lines 10 and 17)	326,474,521		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,581,939,785		1,581,939,785
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	2,207,785		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing	7,900,124		
35	Transmission	83,954,292		
36	Distribution	177,495,357		
37	Customer Accounts	72,110,221		
38	Customer Service and Informational	14,648,450		
39	Sales	487,045		
40	Administrative and General	155,250,102		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	514,053,376		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)	94,863		
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	784,171		
47	Transmission	76,996,864		

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	88,352,448		
49	Administrative and General	189		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	166,228,535		
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,	2,302,648		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	8,684,295		
56	Transmission (Lines 35 and 47)	160,951,156		
57	Distribution (Lines 36 and 48)	265,847,805		
58	Customer Accounts (Line 37)	72,110,221		
59	Customer Service and Informational (Line 38)	14,648,450		
60	Sales (Line 39)	487,045		
61	Administrative and General (Lines 40 and 49)	155,250,291		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	680,281,911		680,281,911
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	2,262,221,696		2,262,221,696
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	997,888,709		997,888,709
69	Gas Plant	353,499,992		353,499,992
70	Other (provide details in footnote):	188,898,026		188,898,026
71	TOTAL Construction (Total of lines 68 thru 70)	1,540,286,727		1,540,286,727
72	Plant Removal (By Utility Departments)			
73	Electric Plant	85,838,799		85,838,799
74	Gas Plant	26,149,748		26,149,748
75	Other (provide details in footnote):	593,142		593,142
76	TOTAL Plant Removal (Total of lines 73 thru 75)	112,581,689		112,581,689
77	Other Accounts (Specify, provide details in footnote):			
78	Other Balance Sheet Salaries and Wages	14,125,323		14,125,323
79	Other Non-Operating Salaries and Wages	11,585,602		11,585,602
80				
81				
82				
83				
84				
85				
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91				
92				
93				
94				
95	TOTAL Other Accounts	25,710,925		25,710,925
96	TOTAL SALARIES AND WAGES	3,940,801,037		3,940,801,037

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report End of <u>2020/Q4</u>
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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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COMMON UTILITY PLANT IN SERVICE

Acct No.	Description	Balance Beginning of Year	Additions	Transfers and Retirements	End Adjustments	Balance of Year
301	Organization	132,411	425,404	0	0	557,815
302	Franchises/Consents	214,735	0	0	0	214,735
303	Intangible Plant	1,598,916,619	192,364,370	(519,424,027)	(109,920)	1,271,747,042
	Total Intangible Plant	1,599,263,765	192,789,774	(519,424,027)	(109,920)	1,272,519,592
389	Land and Land Rights	104,505,016	30,529,172	0	(16,450)	135,017,738
390	Structures and Improvements	2,089,726,553	165,172,726	(26,899,241)	0	2,228,000,038
391b	Personal Computer Hardware	61,150,999	3,135,382	(23,044,051)	0	41,242,330
391a	Office Machines	326,483,043	31,273,768	(90,217,757)	109,920	267,648,974
391c	Office Furniture and Equipment	125,900,276	2,131,533	(3,979,070)	0	124,052,739
392	Transportation Equipment	1,112,226,555	65,438,403	(22,308,653)	0	1,155,356,305
393	Stores Equipment	10,855,901	553,274	0	0	11,409,175

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394 Tools, Shop, and Garage Equipment	70,920,807	9,144,208	(6,330)	0	80,058,685
395 Laboratory Equipment	13,382,250	0	(355,242)	0	13,027,008
396 Power Operated Equipment	190,664,008	46,214,603	(4,582,112)	0	232,296,499
397 Communication Equipment	1,258,046,347	104,913,094	(70,950,549)	0	1,292,008,892
398 Miscellaneous Equipment	40,646,806	(24,465,978)	(112,796)	0	16,068,032 (a)
399 Other Tangible Property	679	0	0	0	679
	-----	-----	-----	-----	-----
Total Non-Landed	5,300,004,224	403,511,013	(242,455,801)	109,920	5,461,169,356
	-----	-----	-----	-----	-----
Total	7,003,773,005	626,829,959	(761,879,828)	(16,450)	6,868,706,686
	-----	-----	-----	-----	-----
101 Property Under Capital Leases	114,312,070	0	0	(16,493,691)	97,818,380
101 Plant Purchased/Sold	(42,345)	0	0	(112,216)	(154,561) (b)
	-----	-----	-----	-----	-----
Total Common Utility Plant in Service	7,118,042,730	626,829,959	(761,879,828)	(16,622,356)	6,966,370,505
	-----	-----	-----	-----	-----
107 Construction Work in Progress - Common Utility Plt.	270,765,820	177,857,260	0	(2,555,008)	446,068,072
	-----	-----	-----	-----	-----
Total Common Utility Plant	7,388,808,550	804,687,219	(761,879,828)	(19,177,364)	7,412,438,577
	=====	=====	=====	=====	=====

NOTES:

(a) For 2020, PG&E refined its methodology for displaying operative CWIP balances by allocating the balances to the respective functional groups to which they belong according to the nature of the costs compared to 2019 where the entire balance was recorded to FERC account 398. As such, included in the 12/31/20 FERC account 398 plant balance is a reversal of the prior year's operative CWIP balance in the additions column. Operative CWIP is defined as capital orders for projects that are less than 30 days of construction with amounts that remain in CWIP due to capital order settlement issues. The balances for these capital orders should be classified as plant.

(b) Plant Purchased or Plant Sold is a holding account for pending transactions related to asset purchases/sales and will be cleared once pending transactions have closed.

ALLOCATION OF COMMON UTILITY PLANT AND
ACCUMULATED PROVISION FOR DEPRECIATION
BASED ON CPUC APPROVED 2020 GENERAL RATE CASE DECISION (D.) 20-12-005

Description	Total	Electric	Gas
-----	-----	-----	-----
Common Utility Plant in Service (a)	6,966,370,505	4,506,899,905	2,459,470,600
Accumulated Provision for Depreciation (a)	2,699,377,396	1,746,767,113	952,610,283

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ALLOCATION OF AD VALOREM TAXES APPLICABLE TO COMMON UTILITY PLANT
BASED ON CPUC APPROVED 2020 GENERAL RATE CASE DECISION (D.) 20-12-005

Description	Amount Charged During Year	Account 408	
		Electric	Gas
Taxes			
Operative Property (b) (from page 262-263)	488,787,259	354,866,840	133,920,419
Common Utility Plant (c) included in above amount	39,383,201	28,453,286	10,929,915

NOTES:

(a) 2020 allocations are based on the methodology of unbundling Common Plant as approved in the 2020 General Rate Case (GRC).

	Electric	Gas
Common Plant in Service Allocation Factors	64.70%	35.30%
Common Plant Accumulated Depreciation Allocation Factors	64.71%	35.29%

(b) Amounts are based on direct charges.

(c) 2020 allocations are based on the methodology of unbundling Common Plant as approved in the 2020 General Rate Case (GRC). 2020 allocations are based on December 2019 and December 2018 allocation factors.

Property tax - Common Allocation Factors	72.26%	27.74%
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ALLOCATION OF DEPRECIATION EXPENSE APPLICABLE TO COMMON UTILITY PLANT
BASED ON CPUC APPROVED 2020 GENERAL RATE CASE DECISION (D.) 20-12-005

Description	Account	Amount Charged During Year	Account 403	
			Electric	Gas

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Depreciation (a)	403	249,209,578	161,263,518	87,946,060
Amortization (a)	404	210,273,078	136,067,709	74,205,369
Total		459,482,657	297,331,227	162,151,430
		=====	=====	=====

ALLOCATION OF MAINTENANCE EXPENSES OF COMMON UTILITY PLANT
BASED ON CPUC APPROVED 2020 GENERAL RATE CASE DECISION (D.) 20-12-005

	Amount	Account 935	
	Charged		
Description	During Year	Electric	Gas
-----	-----	-----	-----
Maintenance of General Plant (d)	5,166,398	3,482,559	1,683,839

Note: Operation expense data was not available.

(d) Allocations factors are based on the 2017 and 2020 Maintenance and Operation Labor Factors approved in the 2017 and 2020 General Rate Cases (GRC). January to November's allocation was based on the 2017 GRC, while December's allocation was based on the 2020 GRC (which was approved in December 2020).

CONSTRUCTION WORK IN PROGRESS (CWIP) - COMMON (ACCOUNT 107)

Description of Project	Amount
-----	-----
7093891 ADMS Phase 0 Cap	23,088,009
7096325 N. Region - Emergency Generation Enhance	18,222,271
70035445 IO - SmartMeterSSN Transition PG&E (CAP)	13,075,760
7096247 Lemoore SC - New Maintenance Building	12,025,424
70038246 FAN Field Area Network	9,804,947
70036182 CC2020 Salesforce - Cap	9,173,680
70042601 Out of Support ESXi Hosts	7,979,883
7096305 Materials & Spoils Bay Covers PH2	7,516,984
70041443 EDGIS/LBGIS Infra/App Re-Arch Ph 2 (CAP)	7,468,137
70042606 Hitachi SAN (Out of Support)	7,190,129
7097606 ADMS Prod Env Concord DCC	6,943,071
7095466 Santa Cruz SC - Site Improvements	6,665,155

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7091574	Network Improvements - Add Alternate	6,559,286
70040540	Recording Systems Lifecycle Replacement	6,344,915
7090325	Auburn SC Regional GC Conversion	5,857,382
7096345	Bay Region-Emergency Generation Enhance	5,703,788
70033756	Bentley SAP Integration - Phase3	5,632,177
7096347	C. Valley - Emergency Generation Enhance	5,430,174
7096346	C. Coast - Emergency Generation Enhance	5,216,110
7096628	ODN Port Enumeration-ICS Patrol (Cap)	4,491,434
7096950	ADMS R1 Build	4,488,061
7097608	ADMS Prod Env Rocklin DCC	4,190,071
7096028	Sacramento SC - Fence Replacement	4,144,066
70039760	Smart Connect (One Portal) CAP	3,878,364
70040221	Sherlock Tool 2.0(C) TO	3,752,255
7096025	Marysville SC - Fence Replacement	3,645,273
7095625	Stockton Mat'l Ctr - Site Improvements	3,422,479
7097607	ADMS Prod Env Fresno DCC	3,392,030
74023500	MII Initiatives 2019	3,219,418
70040222	Sherlock Tool 2.0 (C) DIST	3,148,808
70039263	INSPECT/ENGAGE 2.0 GT (CAP)	3,092,079
7090825	Corp Security-SIS Replacement-Capital	2,945,339
70033741	Express Connects Cap	2,925,692
7095746	San Rafael SC - Fence Replacement	2,717,603
7097565	Wheatland Marysville MDC - Fence Repl	2,687,750
70040983	MTC: Cust Rate - PDP (C)	2,675,761
70039262	INSPECT/ENGAGE 2.0 GD (CAP)	2,665,739
7090505	Corp Security-Replacement of Legacy CCTV	2,641,469
70036362	Extnd PwrBase Line Equip SetMgmt	2,568,291
70043367	SQL Software License	2,565,135
70038240	SCADA Mountain Tops Radios	2,552,183
7097505	R1 ADMS Cutover, CMO & Deploy - CAP	2,547,727
70042761	EGI 2020 Tariff Changes CAP	2,545,138
7094727	GD/GT-GIS Upgrade 2019	2,536,487
7092805	Fresno Thorne Avenue - Develop OU-3	2,512,554
70041340	FT - Common Facilities Coordinated Upgra	2,458,879
7097650	Seismic Racking Improvements PH1	2,428,435
70036143	EES Ph2 (CAP)	2,426,437
70041144	IGP FAN Field Node - Central	2,316,651
70041704	Replace DCCP Storage Hardware VM Sftwr	2,304,308
70041603	Digital Mobile Radio (DMR) Proj Phase II	2,233,249
7094732	GD/GT-GIS Upgrade 2019	2,164,113
70043105	SAF 2.0 Cloud Applications (Detect)	2,059,184
70041464	FT - Router Lifecycle - Internal	2,026,682
7097427	Ukiah SC - Improvements	2,002,488
7097945	NRegion-Emergency Generation Enhance PH2	1,978,500
7096845	San Francisco SC - Investments	1,954,979
70040201	GPOM (GT&S) CAP	1,953,378

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70042500	FT - Network Tools Expansion	1,931,360
7096306	Merced SC - Post Op Readiness	1,925,172
7095885	Sacramento Area - T-Line Fab Shop	1,920,837
7091573	GDCC Predictive Health Analytics	1,867,121
70041140	IGP FAN Field Node - North	1,856,881
70040923	NT - Network 20/20 CAPITAL	1,800,945
70033814	BENTLEY-SAP INTEGRATION DISTRIBUTIVE ENG	1,761,218
70039925	Canal Inspections Ph2	1,629,044
7095229	San Rafael SC - Paving	1,580,075
7093670	CSO AMAG Security Upgrades (75 Sites)	1,577,946
7095210	ODN Network Protection 1009	1,545,729
70041345	FT - DS0 Conversion to MPLS	1,538,723
70038245	FAN SCADA Leases	1,532,338
70042061	2020 Tufin Lifecycle (Cap)	1,489,128
70038243	SCADA Communication Failures	1,462,328
7094665	Gas SCADA Upgrade	1,461,743
70042224	FT -Enterprise Network Management System	1,458,716
70042649	Remediation LAM Ph2 (Cap)	1,456,738
7095745	Lakeville Sub - Fence Replacement	1,443,881
7091575	Network Improvements - Improve WAN	1,435,874
70042604	VNX 7500 Storage	1,427,664
7094728	Locusview	1,415,883
7094666	Gas SCADA Upgrade	1,404,432
70036680	Lifecycle Active Directory (Cap)	1,373,821
70041103	CAISO Initiatives 2020 (C)	1,371,692
70042581	ROADM System Capacity Increase	1,365,563
7095766	San Rafael SC - Investments	1,349,075
70041343	SCADA Radio Capacity/Reliability Imprvmts	1,335,884
7097685	ADMS Cybersecurity Phase 2 CAP	1,317,096
70041143	IGP FAN Field Node - South	1,299,961
70040965	CS - RegAffair Model Integratn Data (C)	1,286,675
7095725	PSPS Capital Equipment - Radio Hardware	1,269,156
70040969	ES - DCPD - PIMS Nuclear Archival (C)	1,267,751
70036150	ET Asset Registry - (CAP)	1,226,177
70041961	MRAD 4.0 Platform Cap	1,223,193
70043205	Pandemic-Deployed Laptops	1,209,137
7095365	AMPS NERC Portal	1,172,412
7097586	Radar and Anti-Drone Tech TO	1,161,296
70041800	ABB Service Suite Upgrade (GD) iOS	1,138,550
70043120	Data Domain - DELL TPA	1,135,798
7095747	Santa Rosa SC - Fence Replacement	1,119,967
70040986	DGT - Consent & Preference Mgmt Ph2 (C)	1,110,590
7096286	EDPI Data Warehouse-CAP	1,108,425
7096185	ADMS Cutover Tool Deployment	1,098,399
7096708	ADMS - Apigee API Platform	1,070,269
70042586	ABB Service Suite Modification TCOM Tech	1,068,228

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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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7098113	NWPU Project 2020 Capex	1,066,108
70040380	IGP FAN Gateway-South	1,055,276
7097506	R1 ADMS Testing - CAP	1,028,644
7083729	TO Radio System Expansion - Gato Ridge	1,022,022
70040303	IGP FAN Gateway-Central	1,012,706
70041548	FT - Network Lifecycle Critical Location	1,008,982
70035447	DCPP Network Switch and WiFi Replacement	1,001,806
70042800	STAR ADF 2.0 (CAP)	997,573
7096951	Harden CRC - IT Kits and Equipment 2020	992,864
70041620	GRC Solution Tool (Cap)	985,619
7094726	Operator Training Simulator	980,826
7096485	Stockton Mat'l Center-Bldg Improvements	979,826
7096907	Strategic Gap Closure Elevated Site GRC	975,976
70035662	DC - OSI PI Platform Capacity Phase 3 -	973,344
70039561	DC Consolidation: CDW Server Upgrade	972,478
7094731	Operator Training Simulator	955,489
7096567	Petaluma SC - Fence Replacement	951,001
7097046	Placerville SC - Risk Mitigation	949,036
7095912	Fresno SC - Fleet Bldg Renov-Expansion	936,393
70039920	DAM Safety Enhancements Ph4 CAP	931,715
7098045	FFIOC - UPS Replacement	926,293
7095985	Merced Regional Center - IT Warehouse	917,282
70041101	FBS Upgrade - Battery Bids (C)	913,545
7097905	CIP003 Low Impact BES PAC	904,837
7097425	Antioch SC - Fence Replacement	895,294
70040975	MTC: Cust Rate - Non Residnt Default (C)	888,863
70042322	MSO - Cust Rev Critical Rpt 2.5 (C)	882,993
7093169	FFIOC-Install Emergency Power Off (EPO)	872,791
7095545	PSPS - IT Equipment for Trailers	854,919
70041241	Lifecycle 2020 Cybersecurity Network Pro	851,815
70037088	IGP - SCADA -ODN Upgrades	847,158
7096225	Wheatland Marysville MDC - Improvements	830,411
70040042	Application Retirement Ph3	823,752
7096707	Marysville SC - Roof Replacement	815,755
70038624	ARAD 5.0 CAP	813,148
70041583	IO-Mcrowv Radio Capcty & Reliab (GRC)	812,767
70043209	ERIM IT Migrate MAOP Rcrd ECTS to Doc C	801,717
70039260	INSPECT/ENGAGE 2.0 ED (CAP)	790,687
70039460	Cyber Gas Data Network (GDN) Segregation	789,701
70040762	Safe Enterprise (Cap)	785,669
7096949	Stockton Mat'l Ctr - Fence Replacement	772,269
70037127	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP TO	757,018
70037128	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP ED	757,018
70037129	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GD	757,018
70037130	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP IT	757,018
70037131	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP HG	757,018

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70043200	IGP DCC Cooling Concord	749,814
70042583	CS - BW and BOBJ Modernization (C)	739,649
70040142	ETAR Facility Rating (CAP)	737,463
7095726	SIPT Radios for SIPT Crews	729,553
70035960	IO-SCADA Radio Cap Reliablty Imrv (TO)	721,918
74017109	Copper Fiber Replacement - Battle Creek	717,101
70034622	Hinkley Comp Station Ntwrk Remediation	711,367
70037242	IO - SCADA Power Reliability: Metcalf Su	704,395
70035941	IO - Kings Craine Microwave Radio Cap In	699,244
7096705	Antioch SC - Investment PH1	687,465
7094646	EM Tool 2019-2020	683,918
70040964	CorpSvc - HR Compensation Mandatory (C)	679,246
70041709	Firewall Lifecycle: MPLS (CAP)	678,985
70042180	CS - Fleet Anywhere Infrass Refresh (C)	677,003
70043202	IGP DCC Cooling Rocklin	673,975
70040200	GPOM (GRCGD) CAP	673,754
7094225	ST - PHYS AMAG SFGO Jump Hosts	663,897
7096565	Red Bluff SC - Fence Replacement	661,150
7096265	SFGO/FFIOC - BMS Control Upgrades	636,807
70041943	FT - UCCE Upgrade: Empirix Lifecycle	626,860
70043384	Network 20/20 Microwave Replacements - A	598,715
70033549	Cyber SS ST - 3rd Party Security and Ris	598,615
70040922	OT - Telecom Circuit Database	587,701
70040984	MTC: Cust Rate - WF POR Securitizatn (C)	587,418
70040040	Substation Record and RecordKeeping PH3	579,605
70036380	IO - SCADA Power Reliability: Table Mtn.	574,782
7097907	CValley-Emergency Generation Enhance PH2	574,552
70043201	IGP DCC Cooling Fresno	573,751
7096245	San Carlos SC - Investments	570,380
70035931	User Behavior Analytics Cap TO	562,872
7096205	Quantum Safe and Key Mgmt (Cap)	552,540
70039926	Canal Inspections Ph2 Web Dashboard	550,042
70042658	FT-Netwrk LC Critical Locations Data Ctr	549,618
7097711	Oakland SC - Fence Replacement	548,179
70032303	Bentley-SAP Integration CAP ED	541,528
7096566	Oroville SC - Fence Replacement	536,603
7095088	MDI - Blast Resist Modular Offices	527,533
7096847	Fremont MDC - Seismic Racking	527,111
70033771	OP: AMSM - Enterprise Network Mgmt Syst	518,828
70033147	Pole Loading Tool Upgrade with Industry	518,727
7096826	Vallejo SC - Trailer Installation	508,812
70032800	Battle Creek - VSAT Emergency Phones	508,089
70042960	DGT - Agency Online Pledge Portal LIP (C)	498,635
7096268	ADMS Build Sprint 1 - Protocol Develop.	488,587
70042624	Gas - Transaction Sys Framewrk Upgrd (C)	482,245
7096065	UST - AST Replacement - Colma	480,653

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74019740	RPM Wave 2 CAP	479,192
7092166	Software & Servers	457,171
7096885	Stockton SC - Emergency Gas Line Repl	453,905
7096445	Livermore SC - Investments	450,520
70039261	INSPECT/ENGAGE 2.0 ET (CAP)	448,731
70041482	IGP PMO (Cap)	441,632
70040000	MW Radio CI& RI (GRC) Harris Upgrades	438,218
70041705	WAN Backhaul Upgrade for Radio WilliamsH	430,749
70041283	ERIM IT Documnt Repository Consolida (C)	426,207
74017108	Kings-Crane Network Extension 426,118	
70037126	EPM - CHANGE CNTRL & AUTH/RE-AUTH CAP GT	420,565
7094647	EM Tool 2019-2020	417,830
7096569	Lakeport SC - Fence Replacement	414,744
70037087	IGP - SCADA - Communication Updgrade	412,194
70041645	ET Substation Asset Registry - (CAP)	408,472
7097085	Grass Valley SC - AST Installation 405,534	
70041342	FT - Teleprotection (TO)	401,953
7097605	ADMS R2 Design CAP	401,790
7097688	San Carlos SC - Paving	401,098
70042900	Critical IT Asset Infra: Infra Assets	400,565
70040321	IGP FAN Gateway-North	389,162
70042182	CS: SIMS Worker Comp Compliance (C)	387,857
7096231	Richmond SC - Improvements	384,216
70041549	FT - Mntr Hrdwr Infra Lfcycl	371,728
7096210	Geyserville SC - Improvements	367,924
7096146	SFGO - RAS Relocation	366,865
70042923	Outage Management Tool - CC Server Upgrd	361,418
70041543	Intelligence Actioning Solution (Cap)	357,005
70029581	EMS SMP Server Replacement	355,629
7095685	Salinas SC - Fence Replacement	352,150
7096672	AMAG Panels and Readers Replc Hydro	349,251
7097445	Willits SC - Building Improvements	347,455
70043121	Gas - Materials Traceability CI P2 (C)	345,259
70038244	SCADA ODN Communications Replacement	342,164
70042823	ODMS Upgrade (C)	336,454
70042643	Click ED CAP	332,248
70037081	IGP - SCADA - Leases	328,483
70043228	FT - AWS Foundational Readiness Phase 1	322,336
7096213	Santa Rosa Office - Improvements	320,440
70042347	FT - Salinas Fiber Replacement	316,769
70038241	SCADA Radios Backhaul & VSAT Upgrade	314,848
7089965	Livermore Sub Training - New Facility	311,192
7097846	NVR Upgrade Replacement	310,800
7097725	DRP DIDF Capital Account 1	308,149
7097050	NERC CIP-013 Supply Chain Risk Managemen	305,952
70041547	FT - WAN Backhaul Upgrade for Radio	305,419

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7095908	Burney SC - Investments	300,483
70039983	MW Radio CI&RI (GRC) Rnd Top Mtn MW Upgr	299,657
70043260	JUMP 2 (Capital)	292,981
7096212	Lakeport SC - Improvements	284,606
70038242	SCADA Master Radios Redundancy	283,997
74017101	Helms T1 Gate House Telecom Path	274,680
7096208	Willits SC - Improvements	272,613
7097285	Systemwide - Weld Shop CAP Improvements	272,379
7096785	SRVCC - PEC Relocation	272,141
7097245	San Carlos SC - Fence Replacement	272,112
70038552	IO - Flea Mtn. Tower Replacement	270,884
70041703	WAN Backhaul Upgrade for Radio UnionHill	265,921
70041702	WAN Backhaul Upgrade for Radio SunsetHil	260,380
7097325	Livermore SC - Fence Replacement	259,267
7096230	Hayward SC - Improvements	255,882
70043227	DGT - Medical Baseline Dr Portal (C)	251,540

Subtotal - Projects with more than \$250,000 in actual costs in CWIP, excluding Research, Development, & Demonstration jobs		\$436,330,671
Aggregate total of projects with less than \$250,000 in actual costs in Construction Work in Progress, including credits representing preliminary billings.		\$9,737,401

TOTAL CWIP - COMMON		\$ 446,068,072

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)	9,322,939	4,219,801	45,302,902	116,045,733
3	Net Sales (Account 447)	(116,645,002)	(52,111,118)	(196,925,007)	(426,288,961)
4	Transmission Rights				
5	Ancillary Services	(6,745,604)	(2,597,942)	(12,787,154)	(26,204,880)
6	Other Items (list separately)				
7	Grid Management Charges	11,589,521	10,436,589	12,794,170	43,195,920
8	FERC Fees	640,504	633,885	1,412,985	3,397,206
9	ISO Congestion				
10	Unaccounted for Energy	8,999,107	16,949,178	14,043,972	21,595,650
11	Congestion Revenue Rights-Hedge	(2,906,629)	(16,101,424)	(5,238,604)	(32,709,217)
12	Congestion Revenue Rights-Auction				
13	Convergence Bidding				
14	Other ISO-related charges:				
15	Minimum Load				
16	Neutrality	(1,143)	(5,793)	323,224	77,321
17	Voltage Support				
18	Other	(485,057)	(2,452,211)	710,919	(2,000,339)
19	Cost Recovery	(1,700,385)	(5,330,652)	(6,466,123)	(18,074,382)
20	Inter Day Ahead SC Trade				
21	Inter Real Time SC Trade				
22	Interest	(291,255)	(245,487)	102,636	(381,245)
23	Capacity - Other	1,324,150	589,278	6,835,939	17,460,963
24	DA IFM Credit Allocation	(3,526,265)	(4,098,706)	(11,673,073)	(26,192,249)
25	RT Offset/Allocation	1,258,896	3,557,985	29,091,718	36,344,236
26	Net Purchases for Energy Storage	38,315	19,652	31,967	187,246
27					
28					
29					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(99,127,908)	(46,536,965)	(122,439,529)	(293,546,998)

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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					N/A	
2	Reactive Supply and Voltage					kW-Month	
3	Regulation and Frequency Response					kW-Month	
4	Energy Imbalance					kWh	
5	Operating Reserve - Spinning					kW-Month	
6	Operating Reserve - Supplement					kW-Month	
7	Other		Various	2,169,879		Various	28,374,759
8	Total (Lines 1 thru 7)			2,169,879			28,374,759

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FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

All Ancillary Services (AS) purchases and sales are covered under the FERC approved ISO Tariff. Definitions of AS under Order No.888 and the ISO Tariff are not consistent with one another. In order to avoid confusion as to meanings and terminologies, ISO AS amounts are not included on these lines but are reported on Line 7.

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

This line includes Ancillary Services as follows:

AS under grandfathered existing contracts

Regulation Service Charge	-	-	-	Flat Charge	0
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ISO related AS activities

Retail ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a)	-	Various	2,169,879	-	Various	28,374,759
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Total			<u>2,169,879</u>			<u>28,374,759</u>
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- (a) This comprised of various billing determinants which the ISO uses to calculate the amounts of AS sold or purchased. This item also includes ISO AS purchases/sales by the Utility in its role as Scheduling Coordinator for ETCs.

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	13,644	16	1900	5,077			100		8,467
2	February	13,509	3	1900	4,852			100		8,557
3	March	12,998	4	1900	4,791			100		8,107
4	Total for Quarter 1				14,720			300		25,131
5	April	13,547	28	2000	6,118			75		7,354
6	May	18,756	26	1900	8,381			55		10,320
7	June	18,523	3	1900	8,490			100		9,933
8	Total for Quarter 2				22,989			230		27,607
9	July	18,081	11	1900	8,740			100		9,241
10	August	20,511	14	1800	9,263			100		11,148
11	September	20,080	7	1800	9,187					10,893
12	Total for Quarter 3				27,190			200		31,282
13	October	16,855	1	1800	7,433			100		9,322
14	November	12,973	30	1900	5,059			100		7,814
15	December	13,252	23	1900	6,246			100		13,152
16	Total for Quarter 4				18,738			300		30,288
17	Total Year to Date/Year				83,637			1,030		114,308

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FOOTNOTE DATA			

Schedule Page: 400 Line No.: 11 Column: b
Entry was estimated in prior period and is now updated to reflect actuals.

Schedule Page: 400 Line No.: 15 Column: e
Actual data is not available at time of filing. Entry reflects estimated data.

Schedule Page: 400 Line No.: 16 Column: h
Entries here represent transmission service to the following Existing Transmission Contract customers:
Transmission Agency of Northern California

Schedule Page: 400 Line No.: 16 Column: j
Transmission services utilizing the Utility's transmission system are also sold by the California Independent System Operator ("ISO") to other wholesale entities. The ISO tracks this data and reports it separately to the FERC. The Utility does not have access to this data. The ISO numbers reported in this column were derived by subtracting columns (e)-(i) from column (b).

Name of Respondent
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 (Mo, Da, Yr)
 04/13/2021

Year/Period of Report
 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									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	36,530,075
3	Steam	5,892,957	23	Requirements Sales for Resale (See instruction 4, page 311.)	18,328,235
4	Nuclear	16,284,423	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	6,285,290	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	624,145	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	777,026	27	Total Energy Losses	33,401,185
8	Less Energy for Pumping	978,655	28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	88,259,495
9	Net Generation (Enter Total of lines 3 through 8)	28,885,186			
10	Purchases	59,363,830			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	553,931			
17	Delivered	543,456			
18	Net Transmission for Other (Line 16 minus line 17)	10,475			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	88,259,491			

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: PACIFIC GAS AND ELECTRIC COMPANY

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	7,050,503		12,139	16	1900
30	February	6,381,625		11,885	3	1900
31	March	6,674,251		11,601	4	1900
32	April	6,088,314		12,231	28	2000
33	May	7,049,894		17,051	26	1900
34	June	7,830,269		16,772	3	1900
35	July	8,632,136		16,480	11	1900
36	August	9,228,219		18,700	14	1800
37	September	8,083,445		18,444	7	1800
38	October	7,466,132		15,383	1	1900
39	November	6,608,249		11,652	9	1900
40	December	7,166,458		11,949	21	1900
41	TOTAL	88,259,495				

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 3 Column: b

This line includes combined cycle plants only. It does not include internal combustion reciprocating engines, which are included on Line 7.

Schedule Page: 401 Line No.: 7 Column: b

This line includes internal combustion reciprocating engines, photo voltaic and Fuel Cells.

This includes photo voltaic generation of 276,791 MWh.

Schedule Page: 401 Line No.: 10 Column: b

For purposes only of accounting for the total energy that went through the Utility's electric system, the MWh for Direct Access ("DA") is **42,262,840 MWh**. It should be noted that DA and DWR megawatts are not Utility purchases and were reported here only because page 401 of the Form 1 does not have any other available line where DA and DWR deliveries can be shown more appropriately.

The Utility acts as a pass-through entity for electricity purchased by the DWR that is sold to the Utility's customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electricity revenue amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Statement of Income.

Schedule Page: 401 Line No.: 22 Column: b

This includes MWh sales for DWR and DA as discussed in the footnote to Line 10, column b.

Schedule Page: 401 Line No.: 26 Column: b

Data for energy used by the Electric department is not separately available but is included on Line 22.

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: <i>DIABLO CANYON 1 & 2</i> (b)	Plant Name: <i>Colusa Gen Station</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Nuclear	Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Outdoor
3	Year Originally Constructed	1968	2010
4	Year Last Unit was Installed	1986	2010
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2323.00	711.45
6	Net Peak Demand on Plant - MW (60 minutes)	2240	657
7	Plant Hours Connected to Load	8335	6356
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	2240	0
10	When Limited by Condenser Water	2240	0
11	Average Number of Employees	1265	24
12	Net Generation, Exclusive of Plant Use - KWh	16284422576	3037656700
13	Cost of Plant: Land and Land Rights	22726560	7889274
14	Structures and Improvements	1104971166	116861278
15	Equipment Costs	6869258263	548000051
16	Asset Retirement Costs	2701010462	3912558
17	Total Cost	1.069E+10	676663161
18	Cost per KW of Installed Capacity (line 17/5) Including	4605.2374	951.1043
19	Production Expenses: Oper, Supv, & Engr	5839138	66485
20	Fuel	110507650	76421468
21	Coolants and Water (Nuclear Plants Only)	31711282	0
22	Steam Expenses	40847332	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2727700	4969240
26	Misc Steam (or Nuclear) Power Expenses	212567566	615313
27	Rents	0	0
28	Allowances	0	17363795
29	Maintenance Supervision and Engineering	2245067	8467
30	Maintenance of Structures	3354092	2038942
31	Maintenance of Boiler (or reactor) Plant	30162140	715162
32	Maintenance of Electric Plant	34113684	5995031
33	Maintenance of Misc Steam (or Nuclear) Plant	48223871	-20674
34	Total Production Expenses	522299522	108173229
35	Expenses per Net KWh	0.0321	0.0356
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MWH	Mcf
38	Quantity (Units) of Fuel Burned	2058618	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	53.442	0.000
42	Average Cost of Fuel Burned per Million BTU	0.653	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.007	0.000
44	Average BTU per KWh Net Generation	10352.408	0.000

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: <i>Gateway Gen Station</i> (d)	Plant Name: <i>Humboldt Gen Station</i> (e)	Plant Name: (f)	Line No.						
Combined Cycle	Internal Combustion		1						
Outdoor	Indoor		2						
2009	2010		3						
2009	2011		4						
619.65	162.70	0.00	5						
580	163	0	6						
6916	8721	0	7						
0	0	0	8						
0	0	0	9						
0	0	0	10						
24	18	0	11						
2855299915	484335703	0	12						
5040000	161399	0	13						
72595612	67489321	0	14						
385694039	157587761	0	15						
3004029	1925852	0	16						
466333680	227164333	0	17						
752.5759	1396.2159	0	18						
58695	16458	0	19						
73094919	15065602	0	20						
0	0	0	21						
11239	0	0	22						
0	0	0	23						
0	0	0	24						
4126271	3537761	0	25						
742859	1302161	0	26						
0	0	0	27						
16901031	3337645	0	28						
7475	2095	0	29						
8702	153192	0	30						
549302	78551	0	31						
3819588	5101746	0	32						
1104636	0	0	33						
100424717	28595211	0	34						
0.0352	0.0590	0.0000	35						
Gas	Oil	Gas		36					
Mcf	Bbl	Mcf		37					
17459945	0	0	5509	3747399	0	0	0	0	38
1041818	0	0	5619132	1041727	0	0	0	0	39
3.600	0.000	0.000	94.870	3.560	0.000	0.000	0.000	0.000	40
3.600	0.000	0.000	97.310	4.600	0.000	0.000	0.000	0.000	41
3.450	0.000	0.000	17.320	4.420	0.000	0.000	0.000	0.000	42
0.020	0.000	0.000	0.140	0.040	0.000	0.000	0.000	0.000	43
6371.000	0.000	0.000	8856.000	8181.000	0.000	0.000	0.000	0.000	44

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. 175 Plant Name: BALCH NO. 1 (b)	FERC Licensed Project No. 175 Plant Name: BALCH NO. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1927	1958
4	Year Last Unit was Installed	1927	1958
5	Total installed cap (Gen name plate Rating in MW)	31.00	97.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	105
7	Plant Hours Connect to Load	8,351	8,604
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	34	105
10	(b) Under the Most Adverse Oper Conditions	34	104
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	44,984,939	251,180,568
13	Cost of Plant		
14	Land and Land Rights	8,128	2,541
15	Structures and Improvements	850,123	5,183,940
16	Reservoirs, Dams, and Waterways	9,592,077	6,749,608
17	Equipment Costs	9,812,524	39,765,759
18	Roads, Railroads, and Bridges	1,326,616	1,739,737
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,589,468	53,441,585
21	Cost per KW of Installed Capacity (line 20 / 5)	696.4345	549.8105
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,174	6,813
25	Hydraulic Expenses	12,488	5,353
26	Electric Expenses	391,949	550,589
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	8,066	11,286
31	Maintenance of Reservoirs, Dams, and Waterways	173,717	198,116
32	Maintenance of Electric Plant	1,030,739	2,290,057
33	Maintenance of Misc Hydraulic Plant	37,432	45,388
34	Total Production Expenses (total 23 thru 33)	1,659,565	3,107,602
35	Expenses per net KWh	0.0369	0.0124

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. 2105 Plant Name: BUTT VALLEY (b)	FERC Licensed Project No. 2105 Plant Name: CARIBOU NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1921
4	Year Last Unit was Installed	1958	1924
5	Total installed cap (Gen name plate Rating in MW)	40.00	73.85
6	Net Peak Demand on Plant-Megawatts (60 minutes)	41	75
7	Plant Hours Connect to Load	7,531	6,533
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	41	75
10	(b) Under the Most Adverse Oper Conditions	38	74
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	105,969,069	95,026,628
13	Cost of Plant		
14	Land and Land Rights	429,639	343,751
15	Structures and Improvements	7,023,193	8,883,823
16	Reservoirs, Dams, and Waterways	36,933,095	28,867,770
17	Equipment Costs	20,645,054	33,691,117
18	Roads, Railroads, and Bridges	3,372,230	5,299,173
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	68,403,211	77,085,634
21	Cost per KW of Installed Capacity (line 20 / 5)	1,710.0803	1,043.8136
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	158,914	551,526
25	Hydraulic Expenses	42,045	104,780
26	Electric Expenses	202,077	2,009,325
27	Misc Hydraulic Power Generation Expenses	1,108,377	3,846,722
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	9,715	144,762
31	Maintenance of Reservoirs, Dams, and Waterways	54,433	333,163
32	Maintenance of Electric Plant	292,350	335,972
33	Maintenance of Misc Hydraulic Plant	95,830	284,260
34	Total Production Expenses (total 23 thru 33)	1,963,741	7,610,510
35	Expenses per net KWh	0.0185	0.0801

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. 803 Plant Name: DE SABLA (b)	FERC Licensed Project No. 2310 Plant Name: DRUM NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1963	1913
4	Year Last Unit was Installed	1963	1928
5	Total installed cap (Gen name plate Rating in MW)	18.45	49.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	19	54
7	Plant Hours Connect to Load	4,567	1,179
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	19	54
10	(b) Under the Most Adverse Oper Conditions	19	54
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	33,537,615	15,547,318
13	Cost of Plant		
14	Land and Land Rights	146,949	1,627,066
15	Structures and Improvements	3,277,838	5,798,355
16	Reservoirs, Dams, and Waterways	42,127,690	43,404,192
17	Equipment Costs	7,009,604	25,589,253
18	Roads, Railroads, and Bridges	4,418,919	1,471,450
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	56,981,000	77,890,316
21	Cost per KW of Installed Capacity (line 20 / 5)	3,088.4011	1,583.1365
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	3,796	27,228
25	Hydraulic Expenses	37,911	25,463
26	Electric Expenses	260,409	653,444
27	Misc Hydraulic Power Generation Expenses	519,706	5,528
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	134,674	69,604
31	Maintenance of Reservoirs, Dams, and Waterways	1,866,885	616,053
32	Maintenance of Electric Plant	176,170	143,729
33	Maintenance of Misc Hydraulic Plant	434,076	35,087
34	Total Production Expenses (total 23 thru 33)	3,433,627	1,576,136
35	Expenses per net KWh	0.1024	0.1014

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. 1988 Plant Name: HAAS (b)	FERC Licensed Project No. 2130 Plant Name: HALSEY (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1958	1916
4	Year Last Unit was Installed	1958	1916
5	Total installed cap (Gen name plate Rating in MW)	135.00	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	144	11
7	Plant Hours Connect to Load	8,338	6,797
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	144	11
10	(b) Under the Most Adverse Oper Conditions	138	11
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	203,137,734	34,207,653
13	Cost of Plant		
14	Land and Land Rights	27,695	1,052,759
15	Structures and Improvements	10,986,073	3,083,810
16	Reservoirs, Dams, and Waterways	28,191,129	29,945,323
17	Equipment Costs	41,633,823	10,873,031
18	Roads, Railroads, and Bridges	731,458	296,672
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	81,570,178	45,251,595
21	Cost per KW of Installed Capacity (line 20 / 5)	604.2235	3,327.3232
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	7,872	14,807
25	Hydraulic Expenses	5,959	14,844
26	Electric Expenses	646,757	135,998
27	Misc Hydraulic Power Generation Expenses	26,627	2,640
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	90,496	2,360
31	Maintenance of Reservoirs, Dams, and Waterways	91,790	1,911,600
32	Maintenance of Electric Plant	500,124	122,155
33	Maintenance of Misc Hydraulic Plant	61,030	662,433
34	Total Production Expenses (total 23 thru 33)	1,430,655	2,866,837
35	Expenses per net KWh	0.0070	0.0838

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. 96 Plant Name: KERCKHOFF NO. 2 (b)	FERC Licensed Project No. 1988 Plant Name: KINGS RIVER (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Underground	Semi-Outdoor
3	Year Originally Constructed	1983	1962
4	Year Last Unit was Installed	1983	1962
5	Total installed cap (Gen name plate Rating in MW)	139.50	48.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	155	52
7	Plant Hours Connect to Load	5,820	7,708
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	155	52
10	(b) Under the Most Adverse Oper Conditions	151	52
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	252,400,000	66,425,532
13	Cost of Plant		
14	Land and Land Rights	584,467	18,829
15	Structures and Improvements	39,020,136	6,078,665
16	Reservoirs, Dams, and Waterways	90,616,637	21,601,373
17	Equipment Costs	52,200,615	24,241,857
18	Roads, Railroads, and Bridges	7,536,560	421,355
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	189,958,415	52,362,079
21	Cost per KW of Installed Capacity (line 20 / 5)	1,361.7091	1,077.4090
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	74,387	3,408
25	Hydraulic Expenses	7,720	3,235
26	Electric Expenses	167,782	257,731
27	Misc Hydraulic Power Generation Expenses	1,068,797	4,099
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	62,193	4,956
31	Maintenance of Reservoirs, Dams, and Waterways	121,638	54,877
32	Maintenance of Electric Plant	315,149	190,702
33	Maintenance of Misc Hydraulic Plant	14,344	6
34	Total Production Expenses (total 23 thru 33)	1,832,010	519,014
35	Expenses per net KWh	0.0073	0.0078

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. 233 Plant Name: PIT NO. 3 (b)	FERC Licensed Project No. 233 Plant Name: PIT NO. 4 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1955
4	Year Last Unit was Installed	1925	1955
5	Total installed cap (Gen name plate Rating in MW)	80.19	103.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	70	95
7	Plant Hours Connect to Load	8,125	8,493
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	70	95
10	(b) Under the Most Adverse Oper Conditions	70	95
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	260,775,254	330,830,296
13	Cost of Plant		
14	Land and Land Rights	3,845,487	298,517
15	Structures and Improvements	13,455,739	3,662,948
16	Reservoirs, Dams, and Waterways	68,856,984	40,926,929
17	Equipment Costs	45,482,082	38,133,250
18	Roads, Railroads, and Bridges	7,811,011	3,731,760
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	139,451,303	86,753,404
21	Cost per KW of Installed Capacity (line 20 / 5)	1,739.0111	838.1971
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	58,732	68,595
25	Hydraulic Expenses	20,724	18,821
26	Electric Expenses	462,742	215,450
27	Misc Hydraulic Power Generation Expenses	762,528	486,493
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	31,493	11,297
31	Maintenance of Reservoirs, Dams, and Waterways	83,637	16,861
32	Maintenance of Electric Plant	565,634	368,764
33	Maintenance of Misc Hydraulic Plant	512,317	83,481
34	Total Production Expenses (total 23 thru 33)	2,497,807	1,269,762
35	Expenses per net KWh	0.0096	0.0038

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. 2107 Plant Name: POE (b)	FERC Licensed Project No. 1962 Plant Name: ROCK CREEK (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1958	1950
4	Year Last Unit was Installed	1958	1950
5	Total installed cap (Gen name plate Rating in MW)	142.83	125.37
6	Net Peak Demand on Plant-Megawatts (60 minutes)	120	126
7	Plant Hours Connect to Load	7,724	8,493
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	120	119
10	(b) Under the Most Adverse Oper Conditions	120	119
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	236,435,773	287,650,524
13	Cost of Plant		
14	Land and Land Rights	821,540	1,777,488
15	Structures and Improvements	4,254,214	22,736,983
16	Reservoirs, Dams, and Waterways	67,309,729	51,799,439
17	Equipment Costs	42,378,946	106,690,007
18	Roads, Railroads, and Bridges	2,019,530	354,677
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	116,783,959	183,358,594
21	Cost per KW of Installed Capacity (line 20 / 5)	817.6431	1,462.5396
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	5,147	11,957
25	Hydraulic Expenses	824,302	67,151
26	Electric Expenses	358,683	1,632,326
27	Misc Hydraulic Power Generation Expenses	2,189,228	4,772,727
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	100,055	410,452
31	Maintenance of Reservoirs, Dams, and Waterways	200,502	1,159,976
32	Maintenance of Electric Plant	352,883	571,258
33	Maintenance of Misc Hydraulic Plant	29,978	24,709
34	Total Production Expenses (total 23 thru 33)	4,060,778	8,650,556
35	Expenses per net KWh	0.0172	0.0301

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. 137 Plant Name: WEST POINT (b)	FERC Licensed Project No. 2310 Plant Name: WISE NO. 1 (c)
1	Kind of Plant (Run-of-River or Storage)	R of R/Storage	R of R/Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1948	1917
4	Year Last Unit was Installed	1948	1917
5	Total installed cap (Gen name plate Rating in MW)	13.60	13.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	15	14
7	Plant Hours Connect to Load	7,798	7,443
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	14
10	(b) Under the Most Adverse Oper Conditions	13	14
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	67,512,660	57,948,822
13	Cost of Plant		
14	Land and Land Rights	141,605	803,771
15	Structures and Improvements	1,005,039	4,119,349
16	Reservoirs, Dams, and Waterways	6,618,927	17,918,597
17	Equipment Costs	7,398,878	10,715,002
18	Roads, Railroads, and Bridges	285,886	226,736
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,450,335	33,783,455
21	Cost per KW of Installed Capacity (line 20 / 5)	1,136.0540	2,484.0776
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	3,074	31,189
25	Hydraulic Expenses	134,160	27,547
26	Electric Expenses	449,436	1,437,662
27	Misc Hydraulic Power Generation Expenses	36,493	5,561
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	110,505	20,843
31	Maintenance of Reservoirs, Dams, and Waterways	381,206	4,272,817
32	Maintenance of Electric Plant	361,871	144,067
33	Maintenance of Misc Hydraulic Plant	20,895	1,804,221
34	Total Production Expenses (total 23 thru 33)	1,497,640	7,743,907
35	Expenses per net KWh	0.0222	0.1336

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
 6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2105 Plant Name: BELDEN (d)	FERC Licensed Project No. 2106 Plant Name: JAMES B. BLACK (e)	FERC Licensed Project No. 619 Plant Name: BUCKS CREEK (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Outdoor	Conventional	2
1969	1965	1928	3
1969	1966	1928	4
117.90	168.66	66.00	5
125	172	65	6
7,346	8,661	3,341	7
			8
125	172	65	9
125	172	53	10
0	0	0	11
247,390,983	448,920,247	36,082,488	12
			13
616,617	509,178	811,840	14
11,899,731	763,768	1,511,509	15
58,367,520	66,295,308	43,801,107	16
64,198,554	19,352,619	32,723,664	17
1,220,208	2,073,862	3,068,472	18
0	0	0	19
136,302,630	88,994,735	81,916,592	20
1,156.0868	527.6576	1,241.1605	21
			22
0	0	0	23
261,741	20,206	123,430	24
52,383	17,696	25,005	25
176,303	598,447	202,021	26
1,825,563	173,943	2,055,246	27
0	0	0	28
0	0	0	29
16,737	34,063	116,791	30
1,067,742	414,737	2,789,263	31
245,121	455,937	185,467	32
77,636	89,357	27,331	33
3,723,226	1,804,386	5,524,554	34
0.0151	0.0040	0.1531	35

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. 2105 Plant Name: CARIBOU NO. 2 (d)	FERC Licensed Project No. 1121 Plant Name: COLEMAN (e)	FERC Licensed Project No. 1962 Plant Name: CRESTA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1958	1979	1949	3
1958	1979	1950	4
117.90	12.15	73.80	5
120	13	70	6
8,349	7,968	8,544	7
			8
120	13	70	9
119	5	72	10
0	0	0	11
343,680,363	28,316,978	159,092,995	12
			13
364,657	180,892	1,365,100	14
11,137,669	1,704,843	11,465,064	15
35,963,846	23,729,148	25,396,958	16
34,398,480	17,868,667	14,952,182	17
464,414	606,322	135,447	18
0	0	0	19
82,329,066	44,089,872	53,314,751	20
698.2957	3,628.7960	722.4221	21
			22
0	0	0	23
243,045	1,020	5,464	24
46,174	12,880	30,016	25
121,042	432,403	179,945	26
1,696,038	252,972	2,180,915	27
0	0	0	28
0	0	0	29
21,226	64,058	88,508	30
63,705	243,065	568,196	31
245,581	174,281	281,432	32
71,226	191,141	12,436	33
2,508,037	1,371,820	3,346,912	34
0.0073	0.0484	0.0210	35

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. 2310 Plant Name: DRUM NO. 2 (d)	FERC Licensed Project No. 2310 Plant Name: DUTCH FLAT (e)	FERC Licensed Project No. 137 Plant Name: ELECTRA (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Outdoor	Conventional	Conventional	2
1965	1943	1948	3
1965	1943	1948	4
53.10	22.00	102.50	5
50	22	98	6
8,174	8,126	8,315	7
			8
50	22	98	9
49	23	98	10
0	0	0	11
215,240,832	89,141,758	286,154,201	12
			13
428,615	824,090	728,576	14
1,157,249	2,757,169	2,651,880	15
12,131,958	21,282,219	31,045,140	16
8,187,656	16,618,809	29,915,505	17
488,443	762,178	1,506,420	18
0	0	0	19
22,393,921	42,244,465	65,847,521	20
421.7311	1,920.2030	642.4148	21
			22
0	0	0	23
21,550	11,703	166,735	24
19,033	11,360	457,059	25
439,823	259,957	1,211,558	26
4,375	14,380	79,405	27
0	0	0	28
0	0	0	29
43,705	55,986	176,320	30
375,416	235,693	920,690	31
52,007	65,849	1,665,637	32
28,430	34,933	72,340	33
984,339	689,861	4,749,744	34
0.0046	0.0077	0.0166	35

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. 2661 Plant Name: HAT CREEK NO. 1 (d)	FERC Licensed Project No. 2661 Plant Name: HAT CREEK NO. 2 (e)	FERC Licensed Project No. 96 Plant Name: KERCKHOFF NO. 1 (f)	Line No.
R of R/Storage	R of R/Storage	R of R/Storage	1
Conventional	Conventional	Conventional	2
1921	1921	1920	3
1921	1921	1920	4
10.00	10.00	22.72	5
9	9	25	6
8,625	6,944	0	7
			8
9	9	25	9
4	9	0	10
0	0	0	11
32,343,278	33,543,126	0	12
			13
778,661	712,895	6,974	14
755,686	283,934	1,651,079	15
2,778,514	1,887,400	3,359,631	16
3,964,049	3,628,621	6,210,712	17
1,178,525	390,699	6,208	18
0	0	0	19
9,455,435	6,903,549	11,234,604	20
945.5435	690.3549	494.4808	21
			22
0	0	0	23
0	0	35,495	24
4,247	3,591	0	25
71,137	94,332	72,345	26
69,919	59,126	509,990	27
0	0	0	28
0	0	0	29
11,248	27,133	499	30
612,601	608,475	9,934	31
72,898	95,667	31,396	32
36,602	37,425	0	33
878,652	925,749	659,659	34
0.0272	0.0276	0.0000	35

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. 1354 Plant Name: A.G. WISHON (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
R of R/Storage			1
Conventional			2
1910			3
1910			4
12.80	0.00	0.00	5
20	0	0	6
6,326	0	0	7
			8
20	0	0	9
12	0	0	10
0	0	0	11
31,547,914	0	0	12
			13
974,124	0	0	14
1,518,393	0	0	15
50,243,503	0	0	16
6,412,671	0	0	17
29,459	0	0	18
0	0	0	19
59,178,150	0	0	20
4,623.2930	0.0000	0.0000	21
			22
0	0	0	23
1,065	0	0	24
0	0	0	25
160,693	0	0	26
461,887	0	0	27
0	0	0	28
0	0	0	29
47,433	0	0	30
81,595	0	0	31
157,484	0	0	32
4,860	0	0	33
915,017	0	0	34
0.0290	0.0000	0.0000	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
 6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 406 Line No.: 11 Column: b

**PACIFIC GAS AND ELECTRIC COMPANY
FOOTNOTES TO HYDRO GENERATING PLANTS - PAGES 406-407
Year ended December 31, 2020**

Schedule Page: 406 Line No.: 11 Column: b

Average Number of Employees on pages 406 and 407 line 11 left blank due to remote operation and remote area headquarters. Refer to the table below for further details on operations and maintenance staffing for each plant. Many of these plants are attended by roving operators as well additional support staff.

PLANT NAME:	REMOTELY OPERATED (Y/N):	REGIONAL OPERATING CENTER:	NUMBER OF OPERATORS:	OPERATIONS HEADQUARTERS:	NUMER OF OPERATORS:	MAINTENANCE HEADQUARTERS:	NUMBER OF SUPPORT STAFF:
PIT NO. 1	Y	None	None	Pit 3 Switching Center	12	Burney Service Center	36
PIT NO. 3	N						
PIT NO. 4	Y						
HAT CREEK NO. 1	Y						
HAT CREEK NO. 2	Y						
PIT NO. 5	N			Pit 5 Switching Center	12		
PIT NO. 6	Y						
PIT NO. 7	Y						
JAMES B. BLACK COLEMAN	Y			Manton Service Center	2	Manton Service Center	10
BUTT VALLEY	Y			Rock Creek Switching Center	19	Rogers Flat Service Center	50
CARIBOU NO. 1	Y						
CARIBOU NO. 2	Y						
BELDEN	Y						
ROCK CREEK	Y						
BUCKS CREEK	Y						
CRESTA	Y						
POE	Y						
DE SABLA	N			Camp 1	3		
				Potter Valley PH	2	Potter Valley PH	1
DRUM NO. 1	N			Drum Switching Center	15	Auburn Service Center	26
DRUM NO. 2	Y						
DUTCH FLAT	Y						
HALSEY	Y			Wise Switching Center	9	Wise PH	3
WISE NO. 1	N					Alta Service Center	8
NEWCASTLE	Y						
SALT SPRINGS	Y			Tiger Creek Switching Center	10	Tiger Creek Service Center	15
TIGER CREEK	Y						
WEST POINT	Y						
ELECTRA	Y						
STANISLAUS	Y			Angels Camp Service Center	3	Angels Camp Service Center Sonora Service Center	16
HAAS	Y	Fresno Operating Center	5	Balch Camp	4	Auberry Service Center	33
BALCH NO. 1	Y						
BALCH NO. 2	Y						
KINGS RIVER	Y						
KERCKHOFF NO. 2	Y			Auberry Service Center	3		
A. G. WISHON	N						

Schedule Page: 406.3 Line No.: 7 Column: f

Schedule Page: 406 Line No.: 7 Column: x

KERCKHOFF NO. 1 hydroelectric plant is no longer operating.

Schedule Page: 406.4 Line No.: 7 Column: d

Schedule Page: 406 Line No.: 7 Column: aa

NARROWS hydroelectric plant was sold to Yuba Water Agency on March 31, 2020.

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. 2735 Plant Name: HELMS PUMPED STORAGE (b)
1	Type of Plant Construction (Conventional or Outdoor)	Underground
2	Year Originally Constructed	1984
3	Year Last Unit was Installed	1984
4	Total installed cap (Gen name plate Rating in MW)	1,053
5	Net Peak Demand on Plant-Megawatts (60 minutes)	1,050
6	Plant Hours Connect to Load While Generating	3,306
7	Net Plant Capability (in megawatts)	1,212
8	Average Number of Employees	24
9	Generation, Exclusive of Plant Use - Kwh	624,145,471
10	Energy Used for Pumping	978,654,714
11	Net Output for Load (line 9 - line 10) - Kwh	-354,509,243
12	Cost of Plant	
13	Land and Land Rights	750,368
14	Structures and Improvements	186,954,368
15	Reservoirs, Dams, and Waterways	451,534,690
16	Water Wheels, Turbines, and Generators	284,232,525
17	Accessory Electric Equipment	69,208,995
18	Miscellaneous Powerplant Equipment	37,711,126
19	Roads, Railroads, and Bridges	8,780,883
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	1,039,172,955
22	Cost per KW of installed cap (line 21 / 4)	986.8689
23	Production Expenses	
24	Operation Supervision and Engineering	1,043,093
25	Water for Power	507,567
26	Pumped Storage Expenses	1,774,490
27	Electric Expenses	2,052,044
28	Misc Pumped Storage Power generation Expenses	2,017,171
29	Rents	
30	Maintenance Supervision and Engineering	5,251
31	Maintenance of Structures	783,427
32	Maintenance of Reservoirs, Dams, and Waterways	3,855,815
33	Maintenance of Electric Plant	6,275,514
34	Maintenance of Misc Pumped Storage Plant	1,463,013
35	Production Exp Before Pumping Exp (24 thru 34)	19,777,385
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	19,777,385
38	Expenses per KWh (line 37 / 9)	0.0317

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	0 FERC Licensed Project No. Plant Name: (d)	0 FERC Licensed Project No. Plant Name: (e)	Line No.
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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	HYDROELECTRIC GENERATING PLANTS:					
2	Alta FERC No.2310	1902	1.00	1.0	2,433,010	14,081,551
3	Centerville FERC No.803	1904	6.40	6.4		17,450,398
4	Chili Bar FERC No.2155	1965	7.02	7.0	20,342,175	18,112,620
5	Coal Canyon	1907				7,033,981
6	Cow Creek FERC No.606	1907	1.44	1.8	4,221,901	3,379,767
7	Crane Valley FERC No.1354	1919	0.99	0.9	611,252	22,743,427
8	Deer Creek FERC No.2310	1908	5.50	5.7	18,088,488	88,088,866
9	Hamilton Branch	1921	5.39	4.8	-119,562	8,594,250
10	Inskip FERC No.1121	1979	7.65	8.0		23,482,362
11	Kern Canyon FERC No. 178	1921	9.54	11.5		
12	Kilarc FERC No.606	1904	3.00	1.6	-62,043	4,325,969
13	Lime Saddle	1906	2.00	2.0		18,755,013
14	Merced Falls FERC No.2467	1930				
15	Oak Flat FERC No.2105	1985	1.40	1.3	6,225,877	8,614,384
16	Phoenix FERC No.1061	1940	1.60	2.0	6,056,579	15,570,071
17	Potter Valley FERC No.77	1910	9.46	9.2	13,134,684	49,456,435
18	San Joaquin No. 1-A FERC No.1354	1919	0.42	0.4		35,436,253
19	San Joaquin No. 2 FERC No.1354	1917	2.88	3.2		32,695,638
20	San Joaquin No. 3 FERC No.1354	1923	4.00	4.2		26,943,042
21	South FERC No.1121	1979	6.75	7.0	11,239,977	16,879,873
22	Spaulding No. 1 FERC No.2310	1928	7.04	7.0	14,094,763	43,591,638
23	Spaulding No. 2 FERC No.2310	1928	3.70	4.4	4,491,750	20,611,238
24	Spaulding No. 3 FERC No.2310	1929	6.61	5.8	21,276,186	18,460,800
25	Spring Gap FERC No.2130	1921	6.00	7.0	20,139,364	12,912,745
26	Toadtown FERC No.803	1986	1.80	1.5	1,966,049	7,281,718
27	Tule FERC No.1333	1914	4.50	6.4		15,033,021
28	Volta No.1 FERC No.1121	1980	8.55	9.0	17,547,670	21,257,037
29	Volta No.2 FERC No.1121	1981	0.95	0.9	1,423,165	3,099,245
30	Wise II FERC No.2310	1986	2.87	3.2	-29,049	13,420,513
31	Miscellaneous Minor					6,809,021
32						
33	Photo Voltaic Generating Plants:					
34	AT&T PARK SOLAR ARRAYS	2007	0.11	0.1	98,257	1,990,928
35	SF SERVICE CENTER SOLAR ARRAY 1 & 2	2007	0.18	0.2	33,679	72,959
36	Vaca Dixon Solar Station	2009	2.00	2.0	3,578,543	10,881,965
37	Five Points - Schindler Solar Station #1	2011	15.00	15.0	24,139,525	54,818,128
38	Westside - Schindler Solar Station #2	2011	15.00	15.0	24,388,943	48,383,100
39	Stroud Solar Station	2011	20.00	20.0	33,705,355	62,417,280
40	Cantua Solar Station	2012	20.00	20.0	42,368,078	56,349,026
41	Giffen Solar Station	2012	10.00	10.0	19,036,014	31,412,761
42	Huron Solar Station	2012	20.00	20.0	37,664,438	61,792,647
43	Gates Solar Station	2013	20.00	20.0	30,953,940	65,649,056
44	West Gates Solar Station	2013	10.00	10.0	19,002,096	77,159,553
45	Guernsey Solar Station	2013	20.00	20.0	41,821,844	35,775,279
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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	Fuel Cell:					
2	San Francisco State	2011	1.60	1.6	5,707,956	8,504,503
3	California State University East Bay	2011	1.40	1.4	10,191,423	6,582,640
4						
5	INTERNAL COMBUSTION:					
6	(EMERGENCY STANDBY UNITS)					
7	Downieville Diesel Plant	1966	0.75			95,289
8	Grass Valley Mobile Diesel Generator	1971	0.25			38,497
9	Sierra City Mobile Diesel Generator	1972	0.33			49,054
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
14,081,551	197,357		330,802	Water		2
2,726,625	274,844		154,283	Water		3
2,580,145	232,665		171,850	Water		4
	21,880		146,811	Water		5
2,347,060	815,798		376,263	Water		6
22,973,159	300,418		238,505	Water		7
16,016,157	57,339		765,451	Water		8
1,594,481	1,066,540		87,180	Water		9
3,069,590	412,813		312,319	Water		10
	142,121		45,562	Water		11
1,441,990	1,060,569		301,389	Water		12
9,377,507	154,681		318,656	Water		13
				Water		14
6,153,131	477,580		106,407	Water		15
9,731,294	486,636		642,749	Water		16
5,227,953	2,674,419		2,330,528	Water		17
84,372,031	197,019		187,924	Water		18
11,352,652	298,379		49,411	Water		19
6,735,761	286,303		52,967	Water		20
2,500,722	428,400		345,692	Water		21
6,191,994	281,879		474,558	Water		22
5,570,605	222,902		230,869	Water		23
2,792,859	241,348		292,750	Water		24
2,152,124	290,412		523,315	Water		25
4,045,399	216,359		135,065	Water		26
3,340,671	33,814		43,969	Water		27
2,486,203	758,845		2,377,952	Water		28
3,262,363	240,932		366,949	Water		29
4,676,137	64,429		1,401,953	Water		30
				Water		31
						32
						33
17,936,287			50,485	Solar		34
405,327				Solar		35
5,440,983	107,842		16,193	Solar		36
3,654,542	59,023		106,467	Solar		37
3,225,540	78,449		97,171	Solar		38
3,120,864	102,128		710,461	Solar		39
2,817,451	81,076		149,033	Solar		40
3,141,276	64,281		56,137	Solar		41
3,089,632	70,019		95,791	Solar		42
3,282,453	39,487		62,072	Solar		43
7,715,955	30,701		36,739	Solar		44
1,788,764	41,858		128,617	Solar		45
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
5,315,314	262,677		345,810	Natural Gas		2
4,701,886	142,200		183,191	Natural Gas		3
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				Diesel		7
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Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 5 Column: a
No federal license required. This power plant was retired on April 1, 2013.

Schedule Page: 410 Line No.: 9 Column: a
No federal license required.

Schedule Page: 410 Line No.: 11 Column: a
This hydroelectric plant was sold to Kern and Tule Hydro LLC on December 30, 2020.

Schedule Page: 410 Line No.: 13 Column: a
No federal license required.

Schedule Page: 410 Line No.: 14 Column: a
This hydroelectric plant was sold to Merced Irrigation District on April 16, 2017.

Schedule Page: 410 Line No.: 31 Column: a
No federal license required.

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	STELLING	MONTA VISTA	115.00	115.00	T SSP	1.61		1
2	LAS AGUILAS SW STA	PANOCHÉ #2	230.00	230.00	SSP	17.44		1
3	LAS AGUILAS SW STA	PANOCHÉ #1	230.00	230.00	T SSP	17.44		1
4	WHISMAN	MONTA VISTA	115.00	115.00	T	5.97		1
5	ATWATER	EL CAPITAN	115.00	115.00	T SSP	7.31		1
6	FULTON	WINDSOR	60.00	60.00	SWP SSP	6.59		1
7	ATWATER	LIVINGSTON-MERCED	115.00	115.00	SWP SSP	24.26		1
8	GALLO	LIVINGSTON	115.00	115.00	SWP SSP	4.20		1
9	ATWATER	CRESSEY	115.00	115.00	SWP SSP	5.91		1
10	GALLO	CRESSEY	115.00	115.00	SWP SSP	14.43		1
11	CRESCENT SW STA	SCULPIN PV	70.00		SSP	0.04		1
12	BAIR	BELMONT	115.00	115.00	SSP	3.64		1
13	IGNACIO	STAFFORD	60.00		SWP SSP	6.13		1
14	BALCH	SANGER	115.00	115.00	T SSP	35.62		1
15	PANOCHÉ	CAL PEAK-STARWOOD	115.00	115.00	SWP	0.10		1
16	FIVE POINTS SW	WHITNEY POINT PV	70.00	70.00	SSP	0.06		1
17	BARTON	AIRWAYS-SANGER	115.00	115.00	T SSP	11.65		1
18	RIPON	MANTECA	115.00	115.00	SWP SSP	9.14		1
19	BELLOTA	RIVERBANK-MELONES SW	115.00	115.00	SWP T SSP	44.65		1
20	TULLOCH TAP		115.00	115.00	SWP SSP	0.31		1
21	MI	WUK-CURTIS	115.00	115.00	SWP SSP	8.40		1
22	BIG BEND	CLAYTON #1	115.00		SWP T	0.02		1
23	BORDEN	GREGG #1	230.00	230.00	T SSP	6.22		1
24	LOS BANOS	PADRE FLAT SW STA	230.00	230.00	T SSP	3.69		1
25	BOGUE	RIO OSO	115.00	115.00	T SSP	21.24		1
26	GREENLEAF #1 TAP		115.00	115.00	SWP SSP	4.84		1
27	LAS GALLINAS	SAN RAFAEL	115.00	115.00	SWP	4.46		1
28	BRIDGEVILLE	COTTONWOOD	115.00	115.00	SWP T SSP	86.06		1
29	INDIAN FLAT	YOSEMITE	70.00	70.00	T SSP	5.00		1
30	BRIGHTON	CLAYTON #1	115.00	115.00	T	6.72		1
31	BORDEN	LOTUS PV	70.00		SSP	0.16		1
32	BRIGHTON	CLAYTON #2	115.00	115.00		6.72		1
33	BRIGHTON	DAVIS	115.00	115.00	SWP T SSP	42.73		1
34	BRIGHTON	DAVIS	115.00	115.00	SWP T SSP	17.36		1
35	BARKER SLOUGH TAP		115.00	115.00	SWP	1.62		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	BRIGHTON	GRAND ISLAND #1	115.00	115.00	SWP T SSP	24.99		1
2	BRIGHTON	GRAND ISLAND #1	115.00	115.00	SWP T SSP	0.14		1
3	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	25.04		1
4	BRIGHTON	GRAND ISLAND #2	115.00	115.00	SWP SSP	0.14		1
5	BRITTON	MONTA VISTA	115.00	115.00	SSP	7.17		1
6	BUTTE VALLEY	CARIBOU	115.00	115.00	SWP T SSP	7.44		1
7	BUTTE	SYCAMORE CREEK	115.00	115.00	SWP SSP	18.17		1
8	CABRILLO	SANTA YNEZ SW STA	115.00	115.00	SWP SSP	14.59		1
9	BUELLTON TAP		115.00	115.00	SWP	1.75		1
10	CALLENDER SW STA	MESA	115.00	115.00	SWP T SSP	13.77		1
11	CAMP EVERS	PAUL SWEET	115.00	115.00	SWP SSP	5.22		1
12	CAMANCHE PUMPING		230.00	230.00	T SSP	0.45		1
13	GRIZZLY TAP (SVP)		115.00	115.00	SWP T	0.16		1
14	CASCADE	COTTONWOOD	115.00	115.00	SWP T SSP	19.46		1
15	CHOWCHILLA	KERCKHOFF	115.00	115.00	SWP T SSP	42.52		1
16	SHARON PRISON TAP		115.00	115.00	SWP SSP	2.57		1
17	OAKHURST TAP		115.00	115.00	SWP SSP	18.16		1
18	CHRISTIE	SOBRANTE	115.00	115.00	T	7.84		1
19	TEICHERT TAP		115.00	115.00	SWP SSP	2.11		1
20	CLAYTON	MEADOW LANE	115.00	115.00	SWP SSP	7.06		1
21	CONTRA COSTA #1		115.00	115.00	T SSP	11.15		1
22	LEPRINO FOODS (TRACY)		115.00	115.00	SWP	0.02		1
23	WILSON	DAIRYLAND (12KV)	115.00	115.00	SWP	11.37		1
24	CONTRA COSTA #2		115.00	115.00		1.41		1
25	FIBREBOARD TAP		115.00	115.00	SWP T SSP	1.03		1
26	COOLEY LANDING	PALO ALTO	115.00	115.00	SWP SSP	2.72		1
27	CORCORAN	OLIVE SW STA	115.00	115.00	T SSP	36.83		1
28	QUEBEC TAP		115.00	115.00	SWP	4.35		1
29	RIO OSO	LINCOLN	115.00	115.00	SWP SSP	11.02		1
30	CORTINA	MENDOCINO #1	115.00	115.00	SWP T	60.95		1
31	LUCERNE #1 TAP		115.00	115.00	SWP SSP	0.23		1
32	COTTONWOOD	PANORAMA	115.00	115.00	SWP SSP	2.95		1
33	CRAG VIEW	CASCADE	115.00	115.00	SWP T	21.61		1
34	DAIRYLAND	MENDOTA	115.00	115.00	SWP T SSP	28.69		1
35	DIVIDE	CABRILLO #2	115.00	115.00	SWP SSP	11.55		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CITY #2 TAP		115.00	115.00	SWP SSP	1.37		1
2	MANVILLE TAP		115.00	115.00	SWP SSP	5.54		1
3	DIVIDE	CABRILLO #1	115.00	115.00	SWP SSP	14.60		1
4	SURF TAP		115.00	115.00	SWP SSP	11.38		1
5	CITY #1 TAP		115.00	115.00	SWP	0.07		1
6	DIXON LANDING	MCKEE	115.00	115.00	SWP SSP	8.30		1
7	DONNELLS	MI-WUK	115.00	115.00	SWP T SSP	18.46		1
8	BEARDSLEY TAP		115.00	115.00	SWP T	2.20		1
9	SPRING GAP TAP		115.00	115.00	SWP T SSP	1.64		1
10	SANDBAR TAP		115.00	115.00	SSP OTHERS	0.10		1
11	FIBREBOARD STANDARD		115.00	115.00	SWP OTHERS	0.02		1
12	DEL MAR	ATLANTIC #1	60.00	60.00	SWP SSP	2.78		1
13	HIGGINS	BELL	115.00	115.00	SWP T SSP	18.77		1
14	BIRDS LANDING SW STA	SHILOH	230.00	230.00	SSP	0.11		1
15	DRUM	RIO OSO #1	115.00	115.00	T SSP	44.64		1
16	DUTCH FLAT #2 TAP		115.00	115.00	SWP T SSP	0.43		1
17	BRUNSWICK #1 TAP		115.00	115.00	T	6.98		1
18	DRUM	RIO OSO #2	115.00	115.00	T SSP	44.65		1
19	BRUNSWICK #2 TAP		115.00	115.00	T	7.00		1
20	DRUM	SUMMIT #1	115.00	115.00	SWP T SSP	27.36		1
21	DRUM	SUMMIT #2	115.00	115.00	SWP T SSP	28.36		1
22	DUMBARTON	NEWARK	115.00	115.00	T SSP	7.14		1
23	EAGLE ROCK	CORTINA	115.00	115.00	SWP SSP	43.38		1
24	EAGLE ROCK	REDBUD	115.00	115.00	SWP T SSP	23.31		1
25	LOWER LAKE	HOMESTAKE	115.00	115.00	SWP SSP	16.12		1
26	EAST GRAND	SAN MATEO	115.00	115.00	T SSP	7.89		1
27	EASTSHORE	DUMBARTON	115.00	115.00	T SSP	12.38		1
28	EASTSHORE	MT EDEN #1	115.00	115.00	T	1.04		1
29	EASTSHORE	MT EDEN #2	115.00	115.00		1.00		1
30	EL CAPITAN	WILSON	115.00	115.00	T SSP	8.12		1
31	EL PATIO	SAN JOSE A	115.00	115.00	SWP T SSP	7.08		1
32	EL DORADO	MISSOURI FLAT #1	115.00	115.00	SWP T SSP	14.43		1
33	APPLE HILL #1 TAP		115.00	115.00	SWP SSP	1.42		1
34	EL DORADO	MISSOURI FLAT #2	115.00	115.00	SWP SSP	14.41		1
35	APPLE HILL #2 TAP		115.00	115.00	SWP SSP	1.43		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	SAN JOSE B	STONE-EVERGREEN	115.00	115.00	SWP SSP	8.56		1
2	NORTECH	NORTHERN RECEIVING	115.00	115.00	SSP	2.21		1
3	H	P #3	115.00	115.00	T OTHERS	0.17		1
4	EXCHEQUER	LE GRAND	115.00	115.00	SWP SSP	29.75		1
5	FELLOWS	MIDSUN	115.00	115.00	SWP SSP	4.92		1
6	FELLOWS	TAFT	115.00	115.00	SWP T SSP	7.93		1
7	MIDSET TAP		115.00	115.00	SWP	0.72		1
8	FULTON JCT	VACA	115.00	115.00	T SSP	11.93		1
9	AMERIGAS TAP		115.00	115.00	SWP SSP	0.49		1
10	FULTON	PUEBLO	115.00	115.00	SWP T SSP	59.95		1
11	RINCON #1 TAP		115.00	115.00	T SSP	0.57		1
12	MONTICELLO PH TAP		115.00	115.00	SWP SSP	0.62		1
13	SILVERADO	FULTON JCT	115.00	115.00	SWP T SSP	26.16		1
14	RINCON #2 TAP		115.00	115.00	SSP	0.55		1
15	FULTON	SANTA ROSA #1	115.00	115.00	SWP T SSP	6.69		1
16	FULTON	SANTA ROSA #2	115.00	115.00	SWP SSP	6.29		1
17	GEYSERS #3	CLOVERDALE	115.00	115.00	SWP T SSP	12.07		1
18	MISSION POWER TAP		115.00	115.00	SWP SSP	1.94		1
19	GEYSERS #3	EAGLE ROCK	115.00	115.00	SWP SSP	1.77		1
20	GEYSERS #5	GEYSERS #3	115.00	115.00	SWP	0.49		1
21	GEYSERS #7	EAGLE ROCK	115.00	115.00	SWP T SSP	1.40		1
22	GOLD HILL	BELLOTA-LOCKEFORD	115.00	115.00	T SSP	87.28		1
23	CAMANCHE TAP		115.00	115.00	SWP SSP	6.71		1
24	GRANT	EASTSHORE #1	115.00	115.00	T SSP	4.33		1
25	GRANT	EASTSHORE #2	115.00	115.00	T	4.20		1
26	GREEN VALLEY	CAMP EVERS	115.00	115.00	SWP T SSP	18.56		1
27	GREEN VALLEY	LLAGAS	115.00	115.00	SWP T SSP	24.85		1
28	METCALF	SALINAS #1	115.00	115.00	T	1.94		1
29	GREEN VALLEY	PAUL SWEET	115.00	115.00	SWP T SSP	15.83		1
30	METCALF	SALINAS #2 (12KV)	115.00	115.00		6.80		1
31	HENRIETTA	LEPRINO SW STA	115.00	115.00	SWP SSP	6.03		1
32	LEPRINO SW STA	HENRIETTA PV	115.00	115.00	SSP	0.06		1
33	KANSAS PV	LEPRINO SW STA	115.00	115.00	SSP	0.17		1
34	LEPRINO SW STA	GWF HANFORD SW STA	115.00	115.00	SWP SSP	12.38		1
35	LEPRINO FOODS	LEPRINO SW STA	115.00	115.00	SWP SSP	6.41		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	GILL RANCH TAP		115.00	115.00	SWP SSP	9.15		1
2	GWF	KINGSBURG	115.00	115.00	SWP SSP	21.64		1
3	PARAMOUNT FARMS TAP		115.00	115.00	SWP SSP	0.57		1
4	HERNDON	BARTON	115.00	115.00	SWP T SSP	12.68		1
5	HERNDON	BULLARD #1	115.00	115.00	T SSP	11.43		1
6	HERNDON	BULLARD #2	115.00	115.00	SWP SSP	11.42		1
7	HERNDON	MANCHESTER	115.00	115.00	SWP SSP	9.27		1
8	HERNDON	WOODWARD	115.00	115.00	SWP T SSP	12.97		1
9	HUMBOLDT BAY	HUMBOLDT #1	115.00	115.00	T SSP	6.31		1
10	HUMBOLDT	BRIDGEVILLE	115.00	115.00	SWP T SSP	30.28		1
11	HUMBOLDT	TRINITY	115.00	115.00	SWP T SSP	68.57		1
12	IGNACIO	MARE ISLAND #1	115.00	115.00	SWP T SSP	39.49		1
13	CARQUINEZ #1 TAP		115.00	115.00	T SSP	0.51		1
14	SKAGGS ISLAND #1 TAP		115.00	115.00	T	0.59		1
15	JAMESON CANYON		115.00	115.00	SSP	0.19		1
16	IGNACIO	MARE ISLAND #2	115.00	115.00	T OTHERS	43.08		1
17	CARQUINEZ #2 TAP		115.00	115.00	SSP	0.52		1
18	SKAGGS ISLAND #2 TAP		115.00	115.00	T	0.60		1
19	IGNACIO	SAN RAFAEL #1	115.00	115.00	T SSP	11.54		1
20	IGNACIO	LAS GALLINAS	115.00	115.00	SWP	4.15		1
21	JARVIS	CRYOGENICS	115.00	115.00	T	0.03		1
22	KERCKHOFF #1	KERCKHOFF #2	115.00	115.00	T SSP	1.58		1
23	KERCKHOFF	CLOVIS-SANGER #1	115.00	115.00	SWP T SSP	37.05		1
24	WOODWARD	SHEPHERD	115.00	115.00	SWP SSP	4.84		1
25	KERCKHOFF	CLOVIS-SANGER #2	115.00	115.00	SWP T SSP	32.05		1
26	KERN OIL	DEXZEL	115.00	115.00	SWP	0.44		1
27	KERN OIL	WITCO	115.00	115.00	T SSP	4.20		1
28	DISCOVERY TAP		115.00	115.00	SWP	2.10		1
29	RIO BRAVO	KERN OIL	115.00	115.00	SWP SSP	7.28		1
30	OLIVE SW STA	SMYRNA	115.00	115.00	T SSP	22.09		1
31	KERN	KERN FRONT	115.00	115.00	SWP SSP	12.50		1
32	DOUBLE C (PSE) TAP		115.00	115.00	SWP	0.06		1
33	BADGER CREEK (PSE) TAP		115.00	115.00	SWP	1.07		1
34	SIERRA (PSE) TAP		115.00	115.00	SWP SSP	1.81		1
35	KERN	TEVIS-STOCKDALE-LAMON	115.00	115.00	SWP T SSP	21.52		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	LAMONT	GRIMMWAY MALAGA	115.00	115.00	SWP SSP	3.55		1
2	LERDO	KERN OIL-7TH STANDARD	115.00	115.00	SWP T SSP	16.35		1
3	KERN	LIVE OAK	115.00	115.00	T SSP	10.83		1
4	KERN	MAGUNDEN-WITCO	115.00	115.00	SWP T SSP	19.58		1
5	KERNWATER TAP		115.00	115.00	SWP SSP	0.67		1
6	WITCO (REFINERY) TAP		115.00	115.00	SWP	0.03		1
7	KERN	ROSEDALE	115.00	115.00	SWP SSP	1.77		1
8	7TH STANDARD	KERN	115.00	115.00	SWP T SSP	6.75		1
9	WHEELER RIDGE	ADOBE SW STA	115.00	115.00	SWP SSP	1.34		1
10	KERN	TEVIS-STOCKDALE	115.00	115.00	SWP T SSP	15.95		1
11	KERN	TEVIS-STOCKDALE (21KV)	115.00	115.00	SWP T SSP	3.71		1
12	KERN	WESTPARK #1	115.00	115.00	T SSP	3.84		1
13	KERN	WESTPARK #2	115.00	115.00	T	3.83		1
14	KIFER	FMC	115.00	115.00	T SSP	6.02		1
15	FMC	SAN JOSE B	115.00	115.00	SSP	1.61		1
16	KINGS RIVER	SANGER-REEDLEY	115.00	115.00	SWP T SSP	43.35		1
17	RAINBOW TAP		115.00	115.00	T SSP	2.59		1
18	KINGSBURG	CORCORAN #1	115.00	115.00	T SSP	27.48		1
19	KINGSBURG	WAUKENA SW STA	115.00	115.00	T SSP	25.26		1
20	FORT BRAGG	ELK	60.00	60.00	SWP SSP	24.02		1
21	PENNGROVE SUB TAP		115.00	115.00	SWP	0.81		1
22	STONY POINT TAP		115.00	115.00	SWP SSP	3.08		1
23	LAKEVILLE	SONOMA #1	115.00	115.00	SWP SSP	6.68		1
24	LAKEVILLE	SONOMA #2	115.00	115.00	SWP SSP	7.18		1
25	LAKEWOOD	MEADOW LANE-CLAYTON	115.00	115.00	SWP T SSP	9.55		1
26	EBMUD TAP		115.00	115.00	OTHERS	0.02		1
27	LAKEWOOD	CLAYTON	115.00	115.00	SSP	5.52		1
28	LAWRENCE	MONTA VISTA	115.00	115.00	SWP T SSP	9.44		1
29	LE GRAND	DAIRYLAND	115.00	115.00	SWP T SSP	11.40		1
30	LE GRAND	CHOWCHILLA	115.00	115.00	SWP T SSP	10.94		1
31	CERTAINTTEED TAP		115.00	115.00	SWP SSP	2.53		1
32	CHOWCHILLA #1 TAP		115.00	115.00	SWP	1.24		1
33	MENDOTA	NORTH STAR SOLAR	115.00	115.00		0.03		1
34	LERDO	FAMOSO	115.00	115.00	SWP T SSP	13.45		1
35	ULTRAPOWDER (OGLE) TAP		115.00	115.00	SWP SSP	2.45		1
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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CAWELO C TAP		115.00	115.00	SWP SSP	1.33		1
2	LIVE OAK TAP		115.00	115.00	SWP SSP	3.97		1
3	LIVE OAK	KERN OIL	115.00	115.00	T	4.40		1
4	VEDDER TAP		115.00	115.00	SWP SSP	11.09		1
5	VALLEY CHILDRENS		115.00	115.00		0.03		1
6	LLAGAS	GILROY FOODS	115.00	115.00	SWP	1.98		1
7	GILROY ENERGY TAP		115.00	115.00	SWP	0.28		1
8	CRAZY HORSE CANYON	SAN BENITO	115.00	115.00	T SSP	8.95		1
9	CRAZY HORSE CANYON	HOLLISTER	115.00	115.00	SSP	17.23		1
10	MADISON	VACA	115.00	115.00	SWP T SSP	22.99		1
11	MANCHESTER	AIRWAYS-SANGER	115.00	115.00	T SSP	15.07		1
12	LAS PALMAS TAP		115.00	115.00	SWP SSP	0.85		1
13	MANTECA	VIERRA	115.00	115.00	SWP T SSP	3.98		1
14	HOWLAND ROAD TAP		115.00	115.00	SWP	0.90		1
15	HEINZ TAP		115.00		SWP	0.79		1
16	MARTIN	DALY CITY #1	115.00	115.00	T	3.93		1
17	MARTIN	DALY CITY #2	115.00	115.00		3.93		1
18	SERRAMONTE TAP		115.00	115.00	T SSP	2.55		1
19	MARTIN	EAST GRAND	115.00	115.00	SWP T SSP	3.96		1
20	MARTIN	MILLBRAE #1	115.00	115.00	T SSP	7.28		1
21	MARTIN	SF AIRPORT	115.00	115.00	T SSP	5.43		1
22	UNITED COGEN INC TAP		115.00	115.00	SWP SSP	0.68		1
23	MARTINEZ	SOBRANTE	115.00	115.00	SSP	16.40		1
24	FAIRVIEW	MARTINEZ SW STA	115.00	115.00	SWP	0.10		1
25	MCCALL	KINGSBURG #1	115.00	115.00	SWP T SSP	11.65		1
26	KINGSBURG COGEN TAP		115.00	115.00	SWP	1.22		1
27	GUARDIAN #2 TAP		115.00	115.00	SWP	0.13		1
28	PANOCHÉ	PANOCHÉ ENERGY	230.00	230.00	SSP	0.09		1
29	MALAGA	KRCD	115.00	115.00	SWP	0.99		1
30	MCCALL	KINGSBURG #2	115.00	115.00	SSP	11.57		1
31	GUARDIAN #1 TAP		115.00	115.00	SWP	0.75		1
32	MCCALL	MALAGA	115.00	115.00	SWP T SSP	10.96		1
33	RANCHERS COTTON TAP		115.00	115.00	SWP SSP	2.10		1
34	RIO BRAVO (FRESNO) TAP		115.00	115.00	SWP OTHERS	0.32		1
35	AIR PRODUCTS TAP		115.00	115.00	SWP	0.29		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	MCCALL	REEDLEY	115.00	115.00	SWP T SSP	15.20		1
2	MCCALL	SANGER #1	115.00	115.00	T SSP	9.23		1
3	MCCALL	SANGER #2	115.00	115.00		9.20		1
4	MCCALL	SANGER #3	115.00	115.00	SWP	8.30		1
5	CALIFORNIA AVE	MCCALL	115.00	115.00	SWP T SSP	23.66		1
6	WEST FRESNO	CALIFORNIA AVE	115.00	115.00	SWP T	4.90		1
7	DANISH CREAMERY TAP		115.00	115.00	SWP	1.20		1
8	MCCALL	WEST FRESNO #2	115.00	115.00	T SSP	19.61		1
9	MCKEE	PIERCY	115.00	115.00	T	7.75		1
10	LOS ESTEROS	MONTAGUE	115.00	115.00	SSP	4.64		1
11	MELONES	CURTIS	115.00	115.00	SWP SSP	14.80		1
12	PEORIA TAP		115.00	115.00	SWP SSP	0.85		1
13	CHINESE CAMP (ULTRA		115.00	115.00	SWP SSP	2.09		1
14	RACETRACK TAP		115.00	115.00	SWP SSP	3.55		1
15	OCEANO	CALLENDER SW STA	115.00	115.00	SWP	4.22		1
16	MELONES	RACETRACK	115.00	115.00	SWP SSP	10.20		1
17	MENDOCINO	REDBUD	115.00	115.00		34.83		1
18	LUCERNE #2 TAP		115.00	115.00	SWP SSP	0.23		1
19	MENDOCINO	UKIAH	115.00	115.00	SWP T SSP	9.83		1
20	MESA	DIVIDE #1	115.00	115.00	T SSP	14.71		1
21	MESA	DIVIDE #2	115.00	115.00		14.72		1
22	MESA	SANTA MARIA	115.00	115.00	SWP T SSP	4.36		1
23	FAIRWAY #1 TAP		115.00	115.00	SWP SSP	2.83		1
24	MESA	SISQUOC	115.00	115.00	SWP T SSP	17.60		1
25	SANTA MARIA COGEN TAP		115.00	115.00	SWP	0.24		1
26	METCALF	COYOTE PUMPING PLANT	115.00	115.00	SWP SSP	7.86		1
27	METCALF	EDENVALE #1	115.00	115.00	T SSP	5.73		1
28	IBM HARRY RD #2 TAP		115.00	115.00	SSP	0.58		1
29	AMES DISTRIBUTION	AMES	115.00	115.00	SSP	0.10		1
30	METCALF	EDENVALE #2	115.00	115.00	T	5.60		1
31	IBM BAILEY AVE TAP		115.00	115.00	SWP SSP	2.00		1
32	METCALF	EL PATIO #1	115.00	115.00	T SSP	14.39		1
33	IBM HARRY RD #1 TAP		115.00	115.00	T	0.58		1
34	METCALF	EL PATIO #2	115.00	115.00		14.40		1
35	METCALF	EVERGREEN #1	115.00	115.00	T	10.63		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	STONE	EVERGREEN-METCALF	115.00	115.00	SWP SSP	12.86		1
2	METCALF	GREEN VALLEY	115.00	115.00	SWP T SSP	25.28		1
3	LOS ESTEROS	TRIMBLE	115.00	115.00	SSP	3.73		1
4	MONTAGUE	TRIMBLE	115.00	115.00	SSP	2.07		1
5	METCALF	MORGAN HILL	115.00	115.00	SSP	9.72		1
6	MIDSUN	MIDWAY	115.00	115.00	SWP T SSP	18.86		1
7	CYMRIC TAP		115.00	115.00	SWP	0.18		1
8	MIDWAY	RENFRO-TUPMAN	115.00	115.00	T SSP	22.60		1
9	TUPMAN-NORCO TAP		115.00	115.00	SWP SSP	6.67		1
10	COLES LEVEE TAP		115.00	115.00	SWP	0.22		1
11	MIDWAY	TUPMAN-RIO	115.00	115.00	SWP T SSP	26.59		1
12	FRITO LAY TAP		115.00	115.00	SWP SSP	0.53		1
13	GOLDEN VALLEY TAP		115.00	115.00	SWP SSP	1.59		1
14	GATES	MUSTANG SW STA #1	230.00	230.00	T SSP	13.17		1
15	GATES	MUSTANG SW STA #2	230.00	230.00	T SSP	13.18		1
16	MIDWAY	SHAFTER	115.00	115.00	SWP T SSP	13.63		1
17	MIDWAY	TAFT	115.00	115.00	T SSP	19.33		1
18	CHARCA	FAMOSO	115.00	115.00	SWP SSP	7.15		1
19	MIDWAY	TEMBLOR	115.00	115.00	SWP T SSP	14.53		1
20	BELRIDGE TAP		115.00	115.00	SWP SSP	6.94		1
21	PSE MCKITTRICK TAP		115.00	115.00	SWP	5.21		1
22	MILLBRAE	SAN MATEO #1	115.00	115.00	T SSP	4.71		1
23	MILPITAS	SWIFT	115.00	115.00	T SSP	8.86		1
24	MABURY TAP		115.00	115.00	SWP SSP	2.81		1
25	LAS PLUMAS TAP		115.00	115.00	SWP SSP	0.48		1
26	MISSOURI FLAT	GOLD HILL #1	115.00	115.00	T SSP	19.73		1
27	MISSOURI FLAT	GOLD HILL #2	115.00	115.00	T	19.69		1
28	STELLING	WOLFE	115.00	115.00	T SSP	1.46		1
29	LOS ESTEROS	AGNEW	115.00	115.00	SWP SSP	1.37		1
30	MORAGA	CLAREMONT #1	115.00	115.00	T OTHERS	5.28		1
31	MORAGA	CLAREMONT #2	115.00	115.00	T OTHERS	5.30		1
32	MORAGA	OAKLAND #1	115.00	115.00	T SSP	5.04		1
33	MORAGA	OAKLAND #2	115.00	115.00		5.04		1
34	MORAGA	OAKLAND #3	115.00	115.00	SWP T SSP	5.05		1
35	MORAGA	OAKLAND #4	115.00	115.00	SWP	5.05		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	MORAGA	OAKLAND J	115.00	115.00	SWP	17.67		1
2	MORAGA	SAN LEANDRO #1	115.00	115.00	T SSP	11.14		1
3	MORAGA	SAN LEANDRO #2	115.00	115.00	SWP	11.01		1
4	MORAGA	SAN LEANDRO #3	115.00	115.00	T SSP	11.00		1
5	MORGAN HILL	LLAGAS	115.00	115.00	SWP T	10.84		1
6	MORRO BAY	SAN LUIS OBISPO #1	115.00	115.00	T	16.01		1
7	MORRO BAY	SAN LUIS OBISPO #2	115.00	115.00	T	16.02		1
8	GOLDTREE TAP		115.00	115.00	SWP SSP	2.30		1
9	FULTON	LAKEVILLE-IGNACIO	230.00	230.00		15.84		1
10	MOSS LANDING	DEL MONTE #1	115.00	115.00	T SSP	23.25		1
11	MOSS LANDING	DEL MONTE #2	115.00	115.00	T SSP	23.29		1
12	MOSS LANDING	GREEN VALLEY #1	115.00	115.00	T SSP	14.22		1
13	MOSS LANDING	GREEN VALLEY #2	115.00	115.00	SWP SSP	14.36		1
14	SARGENT SW STA	HOLLISTER	115.00	115.00	SWP SSP	1.54		1
15	MOSS LANDING	SALINAS #1	115.00	115.00	T SSP	11.99		1
16	DOLAN RD #1 TAP		115.00	115.00	T SSP	0.32		1
17	MOSS LANDING	SALINAS #2	115.00	115.00	SSP	12.03		1
18	DOLAN RD #2 TAP		115.00	115.00	T SSP	0.33		1
19	CRAZY HORSE CANYON	SALINAS-SOLEDAD #1	115.00	115.00	T SSP	35.35		1
20	SAN BENITO	HOLLISTER	115.00	115.00	SSP	8.31		1
21	CRAZY HORSE CANYON	SALINAS-SOLEDAD #2	115.00	115.00	T SSP	35.41		1
22	LLAGAS	HOLLISTER	115.00	115.00	SWP T SSP	21.56		1
23	MTN VIEW	MONTA VISTA	115.00	115.00		4.80		1
24	MOSS LANDING	CRAZY HORSE CANYON #1	115.00	115.00	T SSP	10.52		1
25	NEWARK	AMES #1	115.00	115.00	T	8.30		1
26	NEWARK	AMES #2	115.00	115.00		8.28		1
27	NEWARK	AMES #3	115.00	115.00	SWP T	8.28		1
28	NEWARK	LOS ESTEROS	230.00	230.00	SSP	5.65		1
29	NEWARK	APPLIED MATERIALS	115.00	115.00	SWP T SSP	11.37		1
30	LOCKHEED #2 TAP		115.00	115.00	SWP SSP	1.28		1
31	MOSS LANDING	CRAZY HORSE CANYON #2	115.00	115.00	SSP	10.60		1
32	NEWARK	DIXON LANDING	115.00	115.00	SSP	4.69		1
33	NEWARK	FREMONT #1	115.00	115.00	T SSP	3.71		1
34	NEWARK	FREMONT #2	115.00	115.00	SSP	3.75		1
35	NEWARK	JARVIS #1	115.00	115.00	T SSP	14.25		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	NEWARK	JARVIS #2	115.00	115.00	T SSP	14.48		1
2	NEWARK	KIFER	115.00	115.00	T SSP	10.61		1
3	ZANKER #2 TAP		115.00	115.00	SWP SSP	0.72		1
4	NEWARK	LAWRENCE	115.00	115.00	T OTHERS	10.25		1
5	LOCKHEED #1 TAP		115.00	115.00	SWP SSP	1.72		1
6	MOFFETT FIELD TAP		115.00	115.00	SWP	0.16		1
7	NEWARK	LAWRENCE LAB	115.00	115.00	T	12.21		1
8	NEWARK	MILPITAS #1	115.00	115.00	T SSP	8.48		1
9	NEWARK	MILPITAS #2	115.00	115.00	SWP SSP	10.30		1
10	NEWARK	NUMMI	115.00	115.00	SWP T SSP	4.94		1
11	NEWARK	NORTHERN RECEIVING	115.00	115.00	T SSP	8.76		1
12	NORTHERN RECEIVING	SCOTT #1	115.00	115.00	T SSP	2.08		1
13	NEWARK	NORTHERN RECEIVING	115.00	115.00	T SSP	8.67		1
14	NORTHERN RECEIVING	SCOTT #2	115.00	115.00	SSP	1.98		1
15	NEWARK	TRIMBLE	115.00	115.00	T SSP	12.36		1
16	ZANKER #1 TAP		115.00	115.00	SWP SSP	0.60		1
17	AGNEW TAP		115.00	115.00	SWP SSP	1.32		1
18	P	X #2	115.00	115.00	T SSP	0.28		1
19	NORTH TOWER	MARTINEZ JCT #1 (21KV)	115.00	115.00	T	2.61		1
20	OAKLAND C	MARITIME	115.00	115.00	SWP SSP	2.36		1
21	OAKLAND C	TURBINES	115.00	115.00	SWP SSP	0.19		1
22	OAKLAND J	GRANT	115.00	115.00	T SSP	14.81		1
23	EDES #2 TAP		115.00	115.00	SWP T	0.04		1
24	OLEUM	G #1	115.00	115.00	T SSP	11.29		1
25	VALLEY VIEW #1 TAP		115.00	115.00	SSP	0.96		1
26	OLEUM	G #2	115.00	115.00	OTHERS	11.30		1
27	VALLEY VIEW #2 TAP		115.00	115.00	SSP	0.97		1
28	OLEUM	MARTINEZ	115.00	115.00	SWP T SSP	10.50		1
29	OLEUM	NORTH TOWER-CHRISTIE	115.00	115.00	SWP T SSP	8.33		1
30	CARIBOU	PALERMO	115.00	115.00	SWP T SSP	55.05		1
31	PALERMO	BOGUE	115.00	115.00	T SSP	35.74		1
32	HONCUT TAP		115.00	115.00	T SSP	1.65		1
33	PALERMO	NICOLAUS	115.00	115.00	SWP T SSP	41.18		1
34	PALERMO	PEASE	115.00	115.00	T SSP	26.53		1
35	PANOCHÉ	MENDOTA	115.00	115.00	SWP SSP	10.08		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CHENEY #1 TAP		115.00	115.00	SWP T SSP	4.10		1
2	PANOCHÉ	ORO LOMA	115.00	115.00	SWP T SSP	18.96		1
3	OXFORD TAP		115.00	115.00	SWP	3.87		1
4	WESTLANDS #1 RA		115.00	115.00	SWP SSP	1.05		1
5	SAN LUIS #5 TAP		115.00	115.00	SWP SSP	1.88		1
6	SAN LUIS #3 TAP		115.00	115.00	SWP T SSP	16.11		1
7	DE FRANCESCO TAP		115.00	115.00	SWP SSP	1.02		1
8	EXCELSIOR SW STA	FIVE POINTS PV	115.00	115.00		0.03		1
9	EXCELSIOR SW STA	SCHINDLER #1	115.00	115.00	T SSP	5.24		1
10	EXCELSIOR SW STA	SCHINDLER #2	115.00	115.00	SSP	5.23		1
11	PANOCHÉ	EXCELSIOR SW STA #1	115.00	115.00	T SSP	28.50		1
12	CANTUA TAP		115.00	115.00	SWP SSP	1.83		1
13	WESTLANDS #18 RA TAP		115.00	115.00	SWP SSP	3.52		1
14	KAMM TAP		115.00	115.00	SWP OTHERS	0.52		1
15	PANOCHÉ	EXCELSIOR SW STA #2	115.00	115.00	SSP	28.50		1
16	CHENEY #2 TAP		115.00	115.00	SWP SSP	1.97		1
17	PEASE	RIO OSO	115.00	115.00	SWP T SSP	27.61		1
18	SAN FRANCISCO #2		115.00	115.00		3.15		1
19	PITTSBURG	CLAYTON #1	115.00	115.00	T SSP	16.82		1
20	PITTSBURG	CLAYTON #3	115.00	115.00	T SSP	8.41		1
21	PITTSBURG	CLAYTON #4	115.00	115.00	T SSP	8.32		1
22	PITTSBURG	COLUMBIA STEEL	115.00	115.00	T SSP	9.23		1
23	COLUMBIA SOLAR 115KV		115.00	115.00	SWP SSP	0.45		1
24	LINDE TAP		115.00	115.00	SWP SSP	0.62		1
25	PITTSBURG	LOS MEDANOS #1	115.00	115.00	SSP	0.54		1
26	PITTSBURG	LOS MEDANOS #2	115.00	115.00	SSP	0.54		1
27	PITTSBURG	KIRKER-COLUMBIA STEEL	115.00	115.00	SSP	9.26		1
28	PITTSBURG	MARTINEZ #1	115.00	115.00	T SSP	17.22		1
29	BOLLMAN #1 TAP		115.00	115.00	T SSP	2.14		1
30	IMHOFF TAP		115.00	115.00	SWP SSP	1.43		1
31	PITTSBURG	MARTINEZ #2	115.00	115.00		15.83		1
32	BOLLMAN #2 TAP		115.00	115.00	T SSP	2.19		1
33	PLACER	GOLD HILL #1	115.00	115.00	T SSP	20.67		1
34	FLINT TAP		115.00	115.00	SWP T SSP	1.96		1
35	RAVENSWOOD	AMES #1	115.00	115.00	T	7.07		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	RAVENSWOOD	AMES #2	115.00	115.00		7.09		1
2	RAVENSWOOD	BAIR #1	115.00	115.00	T	7.43		1
3	SHREDDER TAP		115.00	115.00	SWP T SSP	1.38		1
4	RAVENSWOOD	BAIR #2	115.00	115.00	T SSP	11.29		1
5	RAVENSWOOD	COOLEY LANDING #1	115.00	115.00	T	1.62		1
6	RAVENSWOOD	COOLEY LANDING #2	115.00	115.00		1.62		1
7	RAVENSWOOD	PALO ALTO #1	115.00	115.00	SWP T SSP	4.28		1
8	RAVENSWOOD	PALO ALTO #2	115.00	115.00	SWP SSP	4.26		1
9	RAVENSWOOD	SAN MATEO	115.00	115.00	T	12.04		1
10	RIO OSO	NICOLAUS	115.00	115.00	T	5.39		1
11	RIO OSO	WEST SACRAMENTO	115.00	115.00	SWP T SSP	43.56		1
12	RIO OSO	WOODLAND #1	115.00	115.00	SWP T SSP	45.25		1
13	RIO OSO	WOODLAND #2	115.00	115.00	SWP T SSP	53.37		1
14	ZAMORA TAP		115.00	115.00	SWP SSP	1.92		1
15	BELLOTA	RIVERBANK	115.00	115.00	SWP SSP	18.87		1
16	SALT SPRINGS	TIGER CREEK	115.00	115.00	T SSP	16.48		1
17	KM GREEN TAP		115.00	115.00	SSP	0.20		1
18	SAN JOSE A	SAN JOSE B	115.00	115.00	SSP	1.15		1
19	SAN LEANDRO	OAKLND J #1	115.00	115.00	T SSP	6.70		1
20	EDES #1 TAP		115.00	115.00	SWP SSP	0.05		1
21	SAN LUIS OBISPO	OCEANO	115.00	115.00	SWP T SSP	19.90		1
22	SAN LUIS OBISPO	SANTA MARIA	115.00	115.00	SWP SSP	25.96		1
23	SAN MATEO	BAY MEADOWS #1	115.00	115.00	T	4.30		1
24	SAN MATEO	BAY MEADOWS #2	115.00	115.00	T	4.26		1
25	SAN MATEO	BELMONT	115.00	115.00	SWP SSP	7.20		1
26	SAN MATEO	MARTIN #3	115.00	115.00	SWP T SSP	11.55		1
27	SAN MATEO	MARTIN #6	115.00	115.00	SSP	11.68		1
28	SANGER	MALAGA	115.00	115.00	SWP SSP	8.82		1
29	SANTA MARIA	SISQUOC	115.00	115.00	SWP SSP	10.57		1
30	FAIRWAY #2 TAP		115.00	115.00		1.52		1
31	SEMITROPIC	CHARCA	115.00	115.00	SWP SSP	6.91		1
32	SEMITROPIC	MIDWAY #1	115.00	115.00	SWP T SSP	14.10		1
33	SEMITROPIC	MIDWAY #2	115.00	115.00	SWP T SSP	20.11		1
34	WASCO PRISON TAP		115.00	115.00	SWP	0.54		1
35	SF AIRPORT	SAN MATEO	115.00	115.00	T SSP	6.09		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	SHAFTER	RIO BRAVO	115.00	115.00	SWP SSP	8.31		1
2	SIERRA #1		115.00	115.00	T	5.47		1
3	SIERRA #2		115.00	115.00		4.86		1
4	SISQUOC	GAREY	115.00	115.00	SWP SSP	5.02		1
5	SISQUOC	SANTA YNEZ SW STA	115.00	115.00	SWP SSP	22.12		1
6	SANTA YNEZ TAP		115.00	115.00	SWP SSP	4.06		1
7	SMYRNA	SEMITROPIC-MIDWAY	115.00	115.00	SWP T SSP	44.63		1
8	SOBRANTE	G #1	115.00	115.00	SWP T SSP	5.34		1
9	SOBRANTE	G #2	115.00	115.00	SSP	5.39		1
10	SOBRANTE	GRIZZLY-CLAREMONT #1	115.00	115.00	SWP T SSP	19.58		1
11	MORAGA	LAKEWOOD	115.00	115.00	T SSP	15.11		1
12	SOBRANTE	MORAGA	115.00	115.00	SWP T SSP	5.68		1
13	LAKEVILLE	IGNACIO #2	230.00	230.00	T	14.53		1
14	SOBRANTE	GRIZZLY-CLAREMONT #2	115.00	115.00	SWP T SSP	19.30		1
15	SOBRANTE	R #1	115.00	115.00	T SSP	5.54		1
16	SOBRANTE	R #2	115.00	115.00		5.53		1
17	SOBRANTE	STANDARD OIL SW STA #2	115.00	115.00	SSP	18.89		1
18	SAN PABLO #2 TAP		115.00	115.00	T SSP	0.45		1
19	POINT PINOLE TAP		115.00	115.00	SWP SSP	1.30		1
20	SOBRANTE	STANDARD OIL SW STA #1	115.00	115.00	T SSP	18.89		1
21	SAN PABLO #1 TAP		115.00	115.00	SSP	0.44		1
22	SONOMA	PUEBLO	115.00	115.00	SWP SSP	18.48		1
23	STANISLAUS	MANTECA #2	115.00	115.00	SWP T SSP	53.95		1
24	STANISLAUS	MELONES SW	115.00	115.00	SWP T SSP	61.15		1
25	FROGTOWN #1 TAP		115.00	115.00	T	0.12		1
26	STANISLAUS	MELONES SW	115.00	115.00	T SSP	43.80		1
27	RIVERBANK JCT SW STA	RIPON	115.00	115.00	SWP SSP	18.00		1
28	FROGTOWN #2 TAP		115.00	115.00		0.11		1
29	STANISLAUS	NEWARK #1 (12KV)	115.00	115.00	T SSP	15.04		1
30	STANISLAUS	NEWARK #2 (12KV)	115.00	115.00	T SSP	18.17		1
31	MONTA VISTA	WOLFE	115.00	115.00	T SSP	2.72		1
32	STOCKTON A	LOCKEFORD-BELLOTA #1	115.00	115.00	SWP T SSP	34.80		1
33	STOCKTON A	LOCKEFORD-BELLOTA #2	115.00	115.00	SWP T SSP	34.49		1
34	KYOHO TAP		115.00	115.00	SWP SSP	2.20		1
35	SWIFT	METCALF	115.00	115.00	T	8.93		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	TABLE MTN	BUTTE #1	115.00	115.00	SWP T SSP	19.54		1
2	TABLE MTN	BUTTE #2	115.00	115.00	T SSP	15.82		1
3	TAFT	CHALK CLIFF	115.00	115.00	SWP SSP	7.18		1
4	UNIVERSITY COGEN TAP		115.00	115.00	SWP	0.22		1
5	TEMBLOR	KERNRIDGE	115.00	115.00	SWP SSP	4.78		1
6	CAL WATER TAP		115.00	115.00	SWP SSP	2.15		1
7	TEMBLOR	SAN LUIS OBISPO	115.00	115.00	SWP T SSP	57.79		1
8	CARRIZO PLAINS TAP		115.00	115.00	SSP	0.04		1
9	TESLA	SCHULTE SW STA #2	115.00	115.00	T SSP	7.34		1
10	OWENS ILLINOIS TAP		115.00	115.00	SWP	0.68		1
11	LAMMERS	KASSON	115.00	115.00	SWP T SSP	8.23		1
12	TESLA	SCHULTE SW STA #1	115.00	115.00	SWP T SSP	7.39		1
13	LAWRENCE LIVERMORE		115.00	115.00	SWP T	9.41		1
14	AEC SITE #1 TAP		115.00	115.00	SWP T	1.60		1
15	AEC SITE #2 TAP		115.00	115.00	SWP SSP	2.16		1
16	SAFEWAY TAP		115.00	115.00	SWP SSP	0.68		1
17	TESLA	SALADO #1	115.00	115.00	SWP T SSP	32.07		1
18	MILLER #1 TAP		115.00	115.00	SWP T SSP	21.26		1
19	SCHULTE SW STA	LAMMERS	115.00	115.00	T SSP	0.69		1
20	TESLA	SALADO-MANTECA	115.00	115.00	SWP T SSP	53.96		1
21	INGRAM CREEK TAP		115.00	115.00	SWP SSP	0.50		1
22	MILLER #2 TAP		115.00	115.00	SWP SSP	12.32		1
23	TESLA	STOCKTON COGEN JCT	115.00	115.00	SWP T SSP	44.44		1
24	THERMAL ENERGY TAP		115.00	115.00	SWP SSP	0.74		1
25	SAN JOAQUIN COGEN TAP		115.00	115.00	SWP	0.04		1
26	TESLA	TRACY	115.00	115.00	SWP T SSP	25.23		1
27	ELLIS TAP		115.00	115.00	SWP	0.17		1
28	TRIMBLE	SAN JOSE B	115.00	115.00	SSP	2.53		1
29	GISH TAP		115.00	115.00	SWP	0.96		1
30	LOS ESTEROS	NORTECH	115.00	115.00	SSP	1.98		1
31	TRINITY	COTTONWOOD	115.00	115.00	SWP T SSP	45.97		1
32	JESSUP TAP		115.00	115.00	SWP SSP	0.86		1
33	UKIAH	HOPLAND-CLOVERDALE	115.00	115.00	SWP SSP	31.17		1
34	VACA	SUISUN	115.00	115.00	SWP T SSP	23.06		1
35	VACA	SUISUN-JAMESON	115.00	115.00	SWP T SSP	25.46		1
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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	VACA	VACAVILLE-CORDELIA	115.00	115.00	SWP T	22.04		1
2	VACA	VACAVILLE-JAMESON-NOR	115.00	115.00	SWP T SSP	36.18		1
3	WEST SACRAMENTO	BRIGHTON	115.00	115.00	T SSP	13.97		1
4	DEEPWATER #2 TAP		115.00	115.00	SWP SSP	2.45		1
5	WEST SACRAMENTO	DAVIS	115.00	115.00	SWP SSP	12.14		1
6	DEEPWATER #1 TAP		115.00	115.00	T SSP	2.29		1
7	POST OFFICE TAP		115.00	115.00	SWP SSP	0.75		1
8	WESTPARK	MAGUNDEN	115.00	115.00	SWP T SSP	12.29		1
9	BEAR MTN TAP		115.00	115.00	SWP SSP	1.27		1
10	BOLTHOUSE FARMS TAP		115.00	115.00	SWP	0.11		1
11	ADOBE SW STA	LAMONT	115.00	115.00	SWP T SSP	21.20		1
12	ARVIN EDISON TAP		115.00	115.00	SWP	1.06		1
13	WHISMAN	MTN VIEW	115.00	115.00	SWP T	3.54		1
14	WILSON	ATWATER #2	115.00	115.00	T SSP	15.41		1
15	WILSON	LE GRAND	115.00	115.00	SWP T SSP	14.04		1
16	WILSON	MERCED #1	115.00	115.00	SWP T SSP	5.58		1
17	WILSON	MERCED #2	115.00	115.00	SWP T SSP	6.20		1
18	WILSON	ORO LOMA	115.00	115.00	SWP T SSP	43.56		1
19	WOODLAND	DAVIS	115.00	115.00	SWP SSP	11.71		1
20	WOODLAND BIOMASS TAP		115.00	115.00	SWP	0.87		1
21	WOODLEAF	PALERMO	115.00	115.00	SWP T SSP	19.62		1
22	SLY CREEK TAP		115.00	115.00	SWP SSP	5.33		1
23	FORBESTOWN TAP		115.00	115.00	SSP OTHERS	0.22		1
24	KANAKA TAP		115.00	115.00	SWP SSP	2.59		1
25	CAL PEAK	VACA	115.00	115.00	SWP	0.11		1
26	DELEVAN	VACA #2	230.00	230.00	T	71.07		1
27	SHILOH II	BIRDS LANDING SW STA	230.00	230.00	SSP	3.56		1
28	TESLA	LAWRENCE LAB	115.00	115.00	SWP T SSP	9.00		1
29	OLEUM	UNOCAL #1	115.00	115.00		0.01		1
30	OLEUM	UNOCAL #2	115.00	115.00	SWP	0.05		1
31	UNION OIL TAP		115.00	115.00	SWP SSP	0.50		1
32	PLACER	GOLD HILL #2	115.00	115.00	SSP	20.67		1
33	APPLIED MATERIALS	BRITTON	115.00	115.00	SSP	0.47		1
34	SANTA ROSA	CORONA	115.00	115.00	SWP SSP	14.39		1
35	VIERRA	TRACY-KASSON	115.00	115.00	SWP T SSP	10.49		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CORONA	LAKEVILLE	115.00	115.00	SWP SSP	5.79		1
2	NOTRE DAME	BUTTE	115.00	115.00	SWP SSP	2.02		1
3	NEWARK	AMES DISTRIBUTION	115.00	115.00	SWP SSP	8.25		1
4	SYCAMORE CREEK	NOTRE DAME-TABLE MTN	115.00	115.00	SWP SSP	20.33		1
5	PALERMO	WYANDOTTE	115.00	115.00	SWP T SSP	5.30		1
6	PARADISE	TABLE MTN	115.00	115.00	SWP T SSP	33.73		1
7	METCALF	HICKS 1 & 2	115.00	115.00	T SSP	6.62		1
8	PIERCY	METCALF	115.00	115.00	T	4.72		1
9	ARCO	MIDWAY	230.00	230.00	T SSP	43.36		1
10	ATLANTIC	GOLD HILL	230.00	230.00	T	11.11		1
11	BAHIA	MORAGA	230.00	230.00	T	26.92		1
12	BALCH	MCCALL	230.00	230.00		39.76		1
13	BELLOTA	COTTLE	230.00	230.00	T	19.87		1
14	BELLOTA	TESLA #2	230.00	230.00	SSP	37.94		1
15	BELLOTA	WARNERVILLE	230.00	230.00	SSP	22.47		1
16	DELEVAN	CORTINA	230.00	230.00	T	17.97		1
17	BELLOTA	WEBER	230.00	230.00	T SSP	14.26		1
18	GEYSERS #11	EAGLE ROCK	115.00	115.00	SSP	0.64		1
19	EAGLE ROCK	FULTON-SILVERADO	115.00	115.00	T SSP	46.94		1
20	DRUM	HIGGINS	115.00	115.00	SWP T SSP	47.75		1
21	BELL	PLACER	115.00	115.00	SWP T	7.94		1
22	PARADISE	BUTTE	115.00	115.00	SSP OTHERS	13.58		1
23	BORDEN	GREGG #2	230.00	230.00	SSP	6.21		1
24	BRENTWOOD	KELSO	230.00	230.00	T SSP	16.41		1
25	BRIGHTON	BELLOTA	230.00	230.00	T	42.51		1
26	BUCKS CREEK	ROCK CREEK-CRESTA	230.00	230.00	T SSP	9.39		1
27	CARIBOU	TABLE MTN	230.00	230.00	SWP T SSP	54.34		1
28	BELDEN TAP		230.00	230.00	SSP	0.02		1
29	CASTRO VALLEY	NEWARK	230.00	230.00	T	22.71		1
30	COBURN	LAS AGUILAS SW STA	230.00	230.00	T SSP	63.97		1
31	CONTRA COSTA PP	CONTRA COSTA SUB	230.00	230.00	T	1.89		1
32	CONTRA COSTA	BRENTWOOD	230.00	230.00	T SSP	10.06		1
33	CONTRA COSTA	DELTA SWITCHYARD	230.00	230.00	T	18.46		1
34	WINDMASTER TAP		230.00	230.00	SSP	0.11		1
35	NORTH DUBLIN	CAYETANO	230.00	230.00	T	3.02		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	NORTH DUBLIN	VINEYARD	230.00	230.00	T	12.46		1
2	CONTRA COSTA	LAS POSITAS	230.00	230.00	T SSP	23.83		1
3	US WINDPOWER #3 TAP		230.00	230.00	SSP	0.06		1
4	COTTLE	MELONES	230.00	230.00	T SSP	25.94		1
5	TES TAP		230.00	230.00	SWP T SSP	3.28		1
6	CONTRA COSTA	LONE TREE	230.00	230.00		5.61		1
7	VINEYARD	NEWARK	230.00	230.00	T	14.36		1
8	CORTINA	VACA	230.00	230.00	T	53.29		1
9	COTTONWOOD	DELEVAN #1	230.00	230.00	T SSP	71.55		1
10	COTTONWOOD	GLENN	230.00	230.00	T	48.33		1
11	COTTONWOOD	LOGAN CREEK	230.00	230.00	T	59.28		1
12	COTTONWOOD	DELEVAN #2	230.00	230.00	T	71.54		1
13	CRESTA	RIO OSO	230.00	230.00	T SSP	64.79		1
14	DELTA SWITCHING YARD	TESLA	230.00	230.00	T	7.70		1
15	DIABLO PP STANDBY		230.00	230.00	T SSP	0.46		1
16	DIABLO	MESA	230.00	230.00	T	40.34		1
17	DOS AMIGOS PUMPING	PANOCHÉ	230.00	230.00	T SSP	23.68		1
18	NEWARK E	F BUS TIE	230.00	230.00		0.22		1
19	EASTSHORE	SAN MATEO	230.00	230.00	SSP	12.43		1
20	EIGHT MILE ROAD	TESLA	230.00	230.00	T SSP	26.64		1
21	ELECTRA	BELLOTA	230.00	230.00	T SSP	29.23		1
22	FULTON	IGNACIO #1	230.00	230.00	T SSP	40.73		1
23	GATES	ARCO	230.00	230.00	T	35.18		1
24	MUSTANG SW STA	GREGG	230.00	230.00	T SSP	45.47		1
25	MUSTANG SW STA	MCCALL	230.00	230.00	T SSP	42.11		1
26	GATES	PANOCHÉ #1	230.00	230.00	T SSP	43.79		1
27	GATES	PANOCHÉ #2	230.00	230.00	T SSP	43.80		1
28	GEYSERS #12	FULTON	230.00	230.00	T SSP	24.09		1
29	GEYSERS #16 TAP		230.00	230.00	T	1.29		1
30	GEYSERS #17	FULTON	230.00	230.00	T SSP	26.14		1
31	BOTTLE ROCK TAP D.W.R.		230.00	230.00	T	1.07		1
32	GEYSERS #9	LAKEVILLE	230.00	230.00	SSP	41.19		1
33	GEYSERS #9	LAKEVILLE	230.00	230.00	SSP	0.51		1
34	GEYSERS #13 TAP		230.00	230.00	T	2.06		1
35	SANTA FE GEOTHERMAL		230.00	230.00	T SSP	1.04		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	GEYSERS #20 TAP		230.00	230.00		0.03		1
2	GEYSERS #18 TAP		230.00	230.00	T SSP	0.74		1
3	DELEVAN	VACA #3	230.00	230.00	T	71.08		1
4	GOLD HILL	EIGHT MILE ROAD	230.00	230.00	T SSP	48.80		1
5	GOLD HILL	LODI STIG	230.00	230.00	T	46.67		1
6	GREGG	ASHLAN	230.00	230.00	T SSP	7.00		1
7	GREGG	HERNDON #1	230.00	230.00	T	0.60		1
8	GREGG	HERNDON #2	230.00	230.00	T	0.63		1
9	HAAS	MCCALL	230.00	230.00	T SSP	44.21		1
10	HELM	MCCALL	230.00	230.00	T	30.84		1
11	HELMS	GREGG #1	230.00	230.00	T	60.67		1
12	HELMS	GREGG #2	230.00	230.00	T	60.68		1
13	HERNDON	ASHLAN	230.00	230.00	T SSP	6.39		1
14	GATES	MIDWAY	230.00	230.00	T SSP	63.86		1
15	HERNDON	KEARNEY	230.00	230.00	T	10.81		1
16	HICKS	METCALF	230.00	230.00	T SSP	9.07		1
17	IGNACIO	SOBRANTE	230.00	230.00	T SSP	42.49		1
18	KELSO	TESLA	230.00	230.00	T SSP	7.95		1
19	RALPH TAP		230.00	230.00	SSP	0.06		1
20	LAKEVILLE	IGNACIO #1	230.00	230.00	T SSP	15.49		1
21	FULTON	LAKEVILLE	230.00	230.00	T SSP	25.51		1
22	LAKEVILLE	SOBRANTE #2	230.00	230.00	SSP	47.89		1
23	LAKEVILLE	TULUCAY	230.00	230.00	T SSP	17.22		1
24	LAS POSITAS	NEWARK	230.00	230.00	T SSP	20.93		1
25	LOCKEFORD	BELLOTA	230.00	230.00	T	12.32		1
26	PANOCHÉ	TRANQUILLITY SW STA #1	230.00	230.00	T SSP	12.14		1
27	LODI STIG	EIGHT MILE ROAD	230.00	230.00	T SSP	2.18		1
28	EIGHT MILE ROAD	STAGG	230.00	230.00	T SSP	7.20		1
29	DELEVAN	VACA #1	230.00	230.00	T	71.04		1
30	LOS BANOS	DOS AMIGOS	230.00	230.00	T	14.31		1
31	PADRE FLAT SW STA	PANOCHÉ	230.00	230.00	T SSP	33.58		1
32	LOS BANOS	PANOCHÉ #2	230.00	230.00	T SSP	37.13		1
33	LOS BANOS	SAN LUIS PUMPS #1	230.00	230.00	T	3.43		1
34	LOS BANOS	SAN LUIS PUMPS #2	230.00	230.00	T	3.43		1
35	QUINTO SW STA	WESTLEY	230.00	230.00	T	57.55		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	LOS BANOS	QUINTO SW STA	230.00	230.00	T	12.06		1
2	MELONES	WILSON	230.00	230.00	T SSP	61.61		1
3	MONTA VISTA	COYOTE SW STA	230.00	230.00	T	27.83		1
4	METCALF	MONTA VISTA #3	230.00	230.00		28.59		1
5	COYOTE SW STA	METCALF	230.00	230.00	T	0.88		1
6	METCALF	MOSS LANDING #1	230.00	230.00	T SSP	35.76		1
7	METCALF	MOSS LANDING #2	230.00	230.00	SSP	35.76		1
8	MIDDLE FORK	GOLD HILL	230.00	230.00	SWP T SSP	44.08		1
9	MIDWAY	KERN #1	230.00	230.00	T SSP	40.93		1
10	BAKERSFIELD #1 TAP		230.00	230.00	T SSP	7.29		1
11	STOCKDALE #1 TAP		230.00	230.00	T SSP	6.25		1
12	MIDWAY	KERN #3	230.00	230.00	T SSP	20.94		1
13	STOCKDALE #2 TAP		230.00	230.00	T	6.16		1
14	MIDWAY	KERN #4	230.00	230.00	T SSP	20.78		1
15	BAKERSFIELD #2 TAP		230.00	230.00	T	6.62		1
16	MIDWAY	WHEELER RIDGE #1	230.00	230.00	T	52.68		1
17	BUENA VISTA PUMPING		230.00	230.00	T	1.18		1
18	WHEELER RIDGE PUMPING		230.00	230.00	T	0.25		1
19	WIND GAP PUMPING PLANT		230.00	230.00	T	1.64		1
20	MIDWAY	SUNSET	230.00	230.00	T	0.57		1
21	MIDWAY	WHEELER RIDGE #2	230.00	230.00		52.65		1
22	BUENA VISTA PUMPING		230.00	230.00	T	1.21		1
23	WHEELER RIDGE PUMPING		230.00	230.00		0.23		1
24	WIND GAP PUMPING PLANT		230.00	230.00		1.62		1
25	MONTA VISTA	HICKS	230.00	230.00	T SSP	13.27		1
26	SOLAR SW STA	CALIENTE SW STA #1	230.00	230.00	T	8.22		1
27	CALIENTE SW STA	MIDWAY #1	230.00	230.00	T SSP	27.17		1
28	MONTA VISTA	JEFFERSON #1	230.00	230.00	T SSP	19.72		1
29	SOLAR SW STA	CALIENTE SW STA #2	230.00	230.00	T	8.22		1
30	CALIENTE SW STA	MIDWAY #2	230.00	230.00	T	27.16		1
31	MONTA VISTA	JEFFERSON #2	230.00	230.00	SSP	19.73		1
32	MONTA VISTA	SARATOGA	230.00	230.00	T SSP	5.49		1
33	MORAGA	CASTRO VALLEY	230.00	230.00	T	14.92		1
34	MORRO BAY	DIABLO	230.00	230.00		15.78		1
35	MORRO BAY	CALIFORNIA FLATS SW STA	230.00	230.00	T SSP	46.19		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CALIFORNIA FLATS SW STA	GATES	230.00	230.00	T SSP	22.57		1
2	MORRO BAY	MESA	230.00	230.00	T	35.27		1
3	MORRO BAY	SOLAR SW STA #1	230.00	230.00	T SSP	45.55		1
4	MORRO BAY	SOLAR SW STA #2	230.00	230.00	T SSP	45.56		1
5	MOSS LANDING	COBURN	230.00	230.00	SWP T SSP	64.03		1
6	MOSS LANDING	LAS AGUILAS SW STA - 230	230.00	230.00	SSP	51.89		1
7	RAVENSWOOD	SAN MATEO #2	230.00	230.00	SSP	11.88		1
8	LOS ESTEROS	METCALF	230.00	230.00	T SSP	63.25		1
9	TESLA	NEWARK #2	230.00	230.00	SWP T SSP	40.88		1
10	PALERMO	COLGATE	230.00	230.00	T SSP	29.60		1
11	TRANQUILLITY SW STA	HELM	230.00	230.00	T SSP	12.68		1
12	TRANQUILLITY SW STA	KEARNEY	230.00	230.00	T SSP	36.90		1
13	PIT #1	COTTONWOOD	230.00	230.00	SWP T SSP	59.75		1
14	BURNEY FOREST		230.00	230.00	T	0.04		1
15	SPI (BURNEY) TAP		230.00	230.00	T	0.05		1
16	PIT #3	PIT #1	230.00	230.00	T SSP	22.69		1
17	CARBERRY SW STA	ROUND MTN	230.00	230.00	T SSP	12.61		1
18	PIT #5	ROUND MTN #1	230.00	230.00	SWP T SSP	13.12		1
19	COVE ROAD TAP		230.00	230.00	SSP	0.11		1
20	PIT #5	ROUND MTN #2	230.00	230.00	SWP T SSP	13.11		1
21	BLACK TAP		230.00	230.00	T	0.51		1
22	PIT #4 TAP		230.00	230.00	T SSP	7.03		1
23	PIT #6 JCT	ROUND MTN	230.00	230.00	SWP T SSP	8.15		1
24	PIT #6 TAP		230.00	230.00	SWP T SSP	3.43		1
25	PIT #7 TAP		230.00	230.00	SWP T	3.59		1
26	PIT #3	CARBERRY SW STA	230.00	230.00	T SSP	10.91		1
27	ROSSMOOR #1 TAP		230.00	230.00	T	0.69		1
28	CONTRA COSTA	MORAGA #1	230.00	230.00	T SSP	26.76		1
29	CONTRA COSTA	MORAGA #2	230.00	230.00	T SSP	26.83		1
30	ROSSMOOR #2 TAP		230.00	230.00	T	0.66		1
31	PITTSBURG	EASTSHORE	230.00	230.00	SWP T SSP	34.92		1
32	PITTSBURG	SAN MATEO	230.00	230.00	T SSP	47.40		1
33	PITTSBURG	TASSAJARA	230.00	230.00	SSP	17.36		1
34	PANOCHÉ	TRANQUILLITY SW STA #2	230.00	230.00	T SSP	12.14		1
35	PITTSBURG	SAN RAMON	230.00	230.00	SWP T SSP	21.66		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	PITTSBURG	TESORO	230.00	230.00		11.27		1
2	PITTSBURG	TESLA #1	230.00	230.00	T SSP	31.35		1
3	PITTSBURG	TESLA #2	230.00	230.00	SWP T SSP	31.32		1
4	PITTSBURG	TIDEWATER	230.00	230.00	T	11.27		1
5	POE	RIO OSO	230.00	230.00	T SSP	56.09		1
6	RANCHO SECO	BELLOTA #1	230.00	230.00	T	27.39		1
7	RANCHO SECO	BELLOTA #2	230.00	230.00		27.36		1
8	RAVENSWOOD	SAN MATEO #1	230.00	230.00	T SSP	11.89		1
9	RIO OSO	ATLANTIC	230.00	230.00	T SSP	17.68		1
10	RIO OSO	BRIGHTON	230.00	230.00	T	27.17		1
11	RIO OSO	GOLD HILL	230.00	230.00	T	28.63		1
12	RIO OSO	LOCKEFORD	230.00	230.00	T	65.13		1
13	ROCK CREEK	POE	230.00	230.00	SWP T SSP	26.98		1
14	ROUND MTN	COTTONWOOD #2	230.00	230.00	T OTHERS	33.67		1
15	ROUND MTN	COTTONWOOD #3	230.00	230.00	T OTHERS	33.36		1
16	SAN RAMON	MORAGA	230.00	230.00	T SSP	22.24		1
17	TESORO	SOBRANTE	230.00	230.00		12.32		1
18	STAGG	TESLA	230.00	230.00		23.64		1
19	TABLE MTN	PALERMO	230.00	230.00	T OTHERS	14.57		1
20	TABLE MTN	RIO OSO	230.00	230.00		50.18		1
21	JEFFERSON	MARTIN	230.00	230.00	SSP	3.30		1
22	TESLA	NEWARK #1	230.00	230.00	T	28.19		1
23	TESLA	RAVENSWOOD	230.00	230.00	SSP	37.14		1
24	TESLA	TRACY #1	230.00	230.00	T	5.68		1
25	TESLA	TRACY #2	230.00	230.00		5.68		1
26	TESLA	WESTLEY	230.00	230.00	T	45.06		1
27	TIDEWATER	SOBRANTE	230.00	230.00	T SSP	12.32		1
28	TIGER CREEK	ELECTRA	230.00	230.00	T OTHERS	13.65		1
29	TIGER CREEK	VALLEY SPRINGS	230.00	230.00	T OTHERS	24.22		1
30	TULUCAY	VACA	230.00	230.00	T SSP	23.63		1
31	VACA	BAHIA	230.00	230.00	T SSP	33.90		1
32	LAMBIE SW STA	BIRDS LANDING SW STA	230.00	230.00	T	7.04		1
33	VACA	PEABODY	230.00	230.00	T SSP	9.69		1
34	BIRDS LANDING SW STA	CONTRA COSTA PP	230.00	230.00	T SSP	10.20		1
35	VACA	LAKEVILLE #1	230.00	230.00	T SSP	40.93		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	VACA	LAMBIE SW STA	230.00	230.00	T	13.95		1
2	VACA	PARKWAY	230.00	230.00	T SSP	27.76		1
3	VALLEY SPRINGS	BELLOTA	230.00	230.00	T	20.67		1
4	WARNERVILLE	WILSON	230.00	230.00		38.40		1
5	WEBER	TESLA	230.00	230.00	T	23.71		1
6	WILSON	BORDEN #1	230.00	230.00	T SSP	35.31		1
7	COLGATE	RIO OSO	230.00	230.00	T	40.89		1
8	MALACHA TAP		230.00	230.00	T	0.12		1
9	TASSAJARA	NEWARK	230.00	230.00	T SSP	31.80		1
10	SAN RAMON RESEARCH		230.00	230.00	T SSP	3.27		1
11	PARKWAY	MORAGA	230.00	230.00	T	23.64		1
12	SARATOGA	VASONA	230.00	230.00	T SSP	3.41		1
13	VASONA	METCALF	230.00	230.00	T SSP	13.29		1
14	MORRO BAY	TEMPLETON	230.00	230.00	T SSP	16.43		1
15	TEMPLETON	GATES	230.00	230.00	T	52.18		1
16	VACA DIXON	MORAGA #1	230.00	230.00	T	3.08		1
17	NEWARK	RAVENSWOOD	230.00	230.00	T	8.91		1
18	DIABLO UNIT #1		500.00	500.00	T	0.54		1
19	DIABLO UNIT #2		500.00	500.00	T	0.57		1
20	DIABLO	GATES #1	500.00	500.00	T	79.23		1
21	DIABLO	MIDWAY #2	500.00	500.00	T	84.07		1
22	DIABLO	MIDWAY #3	500.00	500.00	T	84.67		1
23	GATES	MIDWAY	500.00	500.00	T SSP	63.78		1
24	LOS BANOS	GATES #1	500.00	500.00	T	80.85		1
25	LOS BANOS	MIDWAY #2	500.00	500.00	T	144.82		1
26	MALIN	ROUND MTN #2	500.00	500.00	T OTHERS	46.90		1
27	MIDWAY	WHIRLWIND	500.00	500.00	T	52.77		1
28	MOSS LANDING	LOS BANOS	500.00	500.00	T SSP	51.33		1
29	MOSS LANDING	METCALF	500.00	500.00	T	34.98		1
30	ROUND MTN	TABLE MTN #1	500.00	500.00	T SSP	89.03		1
31	ROUND MTN	TABLE MTN #2	500.00	500.00	T SSP	89.02		1
32	TABLE MTN	TESLA	500.00	500.00	T OTHERS	134.99		1
33	TABLE MTN	VACA	500.00	500.00	T	83.30		1
34	TESLA	LOS BANOS #1	500.00	500.00	T	57.14		1
35	TESLA	METCALF	500.00	500.00	T	35.31		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	TESLA	TRACY	500.00	500.00	T SSP	1.13		1
2	TRACY	LOS BANOS	500.00	500.00	T SSP	56.23		1
3	VACA	TESLA	500.00	500.00	T	57.00		1
4	ALMENDRA JCT	NICOLAUS	60.00	60.00	SWP SSP	24.90		1
5	RUSSELL CITY ENERGY	EASTSHORE #1	230.00	230.00	SSP	1.19		1
6	RUSSELL CITY ENERGY	EASTSHORE #2	230.00	230.00	SSP	1.20		1
7	LONE TREE	CAYETANO	230.00	230.00	T SSP	15.40		1
8	BIRDS LANDING SW STA	CONTRA COSTA SUB	230.00	230.00	T SSP	9.46		1
9	DEL MAR	ATLANTIC #2	60.00	60.00	SWP SSP	4.42		1
10	PEABODY	BIRDS LANDING SW STA	230.00	230.00	SWP T SSP	19.85		1
11	ATLANTIC	PLEASANT GROVE #1	115.00	115.00	SWP T SSP	5.33		1
12	BAIR	COOLEY LANDING #1	60.00	60.00	SWP T SSP	5.55		1
13	BELLE HAVEN #1 TAP		60.00	60.00	SWP SSP	0.45		1
14	BAIR	COOLEY LANDING #2	60.00	60.00	T SSP	5.60		1
15	BELLE HAVEN #2 TAP		60.00	60.00	SWP	0.40		1
16	BRIDGEVILLE	GARBERVILLE	60.00	60.00	SWP SSP	36.16		1
17	FRUITLAND TAP		60.00	60.00	SWP SSP	4.26		1
18	FORT SEWARD TAP		60.00	60.00	SWP SSP	7.70		1
19	BURNS	LONE STAR #1	60.00	60.00	SWP SSP	5.44		1
20	LONE STAR TAP		60.00	60.00	SWP	1.18		1
21	BURNS	LONE STAR #2	60.00	60.00	SWP SSP	6.31		1
22	CRUSHER TAP		60.00	60.00	SWP SSP	1.94		1
23	BUTTE	CHICO #1	60.00	60.00	SWP	0.79		1
24	BUTTE	CHICO #2	60.00	60.00	SWP	0.74		1
25	BUTTE	ESQUON	60.00	60.00	SWP SSP	9.87		1
26	CARIBOU #2		60.00	60.00	SWP SSP	42.08		1
27	CARIBOU	PLUMAS JCT	60.00	60.00	SWP SSP	21.26		1
28	PLUMAS-SIERRA TAP		60.00	60.00	SWP	0.75		1
29	SIERRA PAC IND (QUINCY)		60.00	60.00	SWP	0.17		1
30	CARIBOU	WESTWOOD	60.00	60.00	SWP SSP	21.10		1
31	CASCADE	BENTON-DESCHUTES	60.00	60.00	SWP SSP	15.98		1
32	WINTU TAP		60.00	60.00	SWP SSP	1.86		1
33	CENTERVILLE	TABLE MTN	60.00	60.00	SWP SSP	21.50		1
34	CENTERVILLE	TABLE MTN-OROVILLE	60.00	60.00	SWP SSP	26.11		1
35	LOGAN CREEK	DELEVAN	230.00	230.00	T	12.35		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CHRISTIE	FRANKLIN #1	60.00	60.00	SWP SSP	5.01		1
2	UNION CHEMICAL TAP		60.00	60.00	SWP SSP	1.04		1
3	CHRISTIE	FRANKLIN #2	60.00	60.00	SWP SSP	5.11		1
4	SEQUOIA TAP		60.00	60.00	SWP	0.40		1
5	CHRISTIE	WILLOW PASS	60.00	60.00	SWP T SSP	15.93		1
6	PORT COSTA BRICK TAP		60.00	60.00	SWP SSP	0.05		1
7	PORT COSTA BRICK TAP		60.00	60.00	SWP SSP	1.84		1
8	STAUFFER TAP		60.00	60.00	SWP SSP	0.58		1
9	URICH TAP		60.00	60.00	SWP	0.21		1
10	DRUM PH #2 TAP		115.00	115.00	SWP SSP	0.09		1
11	KONOCTI	MIDDLETOWN	60.00	60.00	SWP SSP	19.87		1
12	CLEAR LAKE	HOPLAND	60.00	60.00	SWP SSP	11.54		1
13	COBURN	BASIC ENERGY	60.00	60.00	SWP SSP	3.39		1
14	COBURN	OIL FIELDS #1	60.00	60.00	SWP SSP	29.46		1
15	TEXACO TAP		60.00	60.00	SWP SSP	0.72		1
16	COBURN	OIL FIELDS #2	60.00	60.00	SWP SSP	31.05		1
17	SAN ARDO TAP		60.00	60.00	SWP SSP	0.34		1
18	COLEMAN	COTTONWOOD	60.00	60.00	SWP SSP	8.58		1
19	COLEMAN	RED BLUFF	60.00	60.00	SWP SSP	48.31		1
20	COLEMAN	SOUTH	60.00	60.00	SWP SSP	13.39		1
21	COLGATE PH	COLGATE SW STA	60.00	60.00	SSP	0.19		1
22	COLGATE	ALLEGHANY	60.00	60.00	SWP SSP	24.55		1
23	COLGATE	CHALLENGE	60.00	60.00	SWP SSP	13.04		1
24	COLGATE	GRASS VALLEY	60.00	60.00	SWP T SSP	13.17		1
25	COLGATE	PALERMO	60.00	60.00	SWP SSP	22.65		1
26	COLGATE	SMARTVILLE #1	60.00	60.00	SWP SSP	11.26		1
27	NARROWS #1 TAP		60.00	60.00	SWP SSP	2.65		1
28	COLGATE	SMARTVILLE #2	60.00	60.00	SWP SSP	11.19		1
29	NARROWS #2 TAP		60.00	60.00	SWP SSP	3.10		1
30	SMARTVILLE TAP		60.00	60.00	SWP	0.09		1
31	CONTRA COSTA	DU PONT	60.00	60.00	SWP T	2.65		1
32	GWF #4 TAP		60.00	60.00	SWP T	0.25		1
33	CONTRA COSTA	PITTSBURG	60.00	60.00	SWP T SSP	6.28		1
34	CONTRA COSTA	SHELL CHEMICAL#1(21KV)	60.00	60.00		9.55		1
35	PITTSBURG #1 TAP (NO		60.00	60.00	SSP	1.15		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	COOLEY LANDING	LOS ALTOS	60.00	60.00	SWP T SSP	14.89		1
2	COOLEY LANDING	LOS ALTOS (12KV)	60.00	60.00	SWP T SSP	1.41		1
3	WESTINGHOUSE TAP		60.00	60.00	SWP T SSP	7.97		1
4	COOLEY LANDING	STANFORD	60.00	60.00	SWP SSP	6.04		1
5	MENLO TAP		60.00	60.00	SWP	0.36		1
6	CORTINA #1		60.00	60.00	SWP SSP	26.29		1
7	HARRINGTON TAP		60.00	60.00	SWP	0.53		1
8	CORTINA #2		60.00	60.00	SWP SSP	26.61		1
9	ARBUCKLE TAP		60.00	60.00	SWP SSP	0.82		1
10	CORTINA #3		60.00	60.00	SWP SSP	24.80		1
11	WADHAM TAP		60.00	60.00	SWP	1.68		1
12	BIRDS LANDING SW STA	RUSSELL	230.00	230.00	SSP	0.11		1
13	CORTINA #4		60.00	60.00	SWP SSP	45.28		1
14	COTTONWOOD #1		60.00	60.00	SWP T SSP	48.16		1
15	COTTONWOOD #2		60.00	60.00	SWP T SSP	23.63		1
16	RED BANK TAP		60.00	60.00	SWP SSP	0.68		1
17	COTTONWOOD	BENTON #1	60.00	60.00	SWP SSP	15.53		1
18	COTTONWOOD	BENTON #2	60.00	60.00	SWP SSP	14.67		1
19	COTTONWOOD	RED BLUFF	60.00	60.00	SWP SSP	16.78		1
20	UC DAVIS #1 TAP		115.00	115.00	SWP SSP	1.64		1
21	UC DAVIS #2 TAP		115.00	115.00	SWP SSP	1.61		1
22	DEER CREEK	DRUM	60.00	60.00	SWP SSP	6.24		1
23	DEL MONTE	MONTEREY	60.00	60.00	SWP SSP	2.53		1
24	DEL MONTE	VIEJO	60.00	60.00	SWP SSP	7.92		1
25	NAVY LAB TAP		60.00	60.00	SWP	0.19		1
26	DESABLA	CENTERVILLE	60.00	60.00	SWP T SSP	5.86		1
27	ORO FINO TAP		60.00	60.00	SWP SSP	1.30		1
28	FORKS OF THE BUTTE TAP		60.00	60.00	SWP	0.20		1
29	DIXON	VACA #1	60.00	60.00	SWP T SSP	18.35		1
30	TRAVIS TAP		60.00	60.00	SWP SSP	2.88		1
31	DIXON	VACA #2	60.00	60.00	SWP SSP	26.77		1
32	CACHE SLOUGH TAP		60.00	60.00	SWP SSP	6.85		1
33	DELTA	MTN GATE JCT	60.00	60.00	SWP T SSP	15.14		1
34	LODI	INDUSTRIAL	60.00	60.00	SWP SSP	0.98		1
35	DRUM	GRASS VALLEY-WEIMAR	60.00	60.00	SWP SSP	31.17		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CAPE HORN TAP		60.00	60.00	SWP	0.31		1
2	ROLLINS TAP		60.00	60.00	SWP SSP	0.73		1
3	DRUM	SPAULDING	60.00	60.00	SWP SSP	9.36		1
4	ESSEX JCT	ARCATA-FAIRHAVEN	60.00	60.00	SWP T SSP	16.05		1
5	BLUE LAKE TAP		60.00	60.00	SWP SSP	3.70		1
6	BLUE CHIP MILLING TAP		60.00	60.00	SWP	0.42		1
7	ULTRA POWER TAP		60.00	60.00	SWP SSP	1.17		1
8	SIMPSON-KORBEL TAP		60.00	60.00	SWP	0.39		1
9	JANES CREEK TAP		60.00	60.00	SWP	1.78		1
10	ESSEX JCT	ORICK	60.00	60.00	SWP SSP	31.29		1
11	TRINIDAD TAP		60.00	60.00	SWP	1.34		1
12	EUREKA	STA A	60.00	60.00	SWP	0.22		1
13	ALMADEN	LOS GATOS	60.00	60.00	SWP SSP	6.38		1
14	EVERGREEN	ALMADEN	60.00	60.00	SWP	4.96		1
15	JEFFERSON #1		60.00	60.00	SWP T	9.05		1
16	EVERGREEN	MABURY	60.00	60.00	SWP	5.48		1
17	SENER #1 TAP		60.00	60.00	SWP	0.23		1
18	JENNINGS TAP		60.00	60.00	SWP	0.14		1
19	FAIRHAVEN #1		60.00	60.00	SWP SSP	0.47		1
20	CLEAR LAKE	KONOCTI	60.00	60.00	SWP SSP	10.99		1
21	FAIRHAVEN POWER CO		60.00	60.00	SWP SSP	0.50		1
22	FAIRHAVEN	HUMBOLDT	60.00	60.00	SWP SSP	15.54		1
23	KONOCTI	EAGLE ROCK	60.00	60.00	SWP SSP	9.66		1
24	FRENCH MEADOWS	MIDDLE FORK	60.00	60.00	SWP SSP	13.19		1
25	FULTON	CALISTOGA	60.00	60.00	SWP SSP	64.61		1
26	FULTON	HOPLAND	60.00	60.00	SWP SSP	41.10		1
27	FITCH MTN #1 TAP		60.00	60.00	SWP SSP	0.86		1
28	HEALDSBURG #1 TAP		60.00	60.00	SWP SSP	0.25		1
29	WINDSOR	FITCH MOUNTAIN	60.00	60.00	SWP SSP	21.24		1
30	FITCH MTN #2 TAP		60.00	60.00	SWP	0.07		1
31	HEALDSBURG #2 TAP		60.00	60.00	SWP SSP	0.16		1
32	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	20.52		1
33	FULTON	MOLINO-COTATI	60.00	60.00	SWP SSP	0.35		1
34	WASHOE TAP		60.00	60.00	SWP SSP	1.04		1
35	LAGUNA TAP		60.00	60.00	SWP SSP	1.68		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	GLENN #1		60.00	60.00	SWP SSP	33.37		1
2	ELK CREEK TAP		60.00	60.00	SWP SSP	20.44		1
3	GLENN #2		60.00	60.00	SWP SSP	34.69		1
4	GLENN #3		60.00	60.00	SWP SSP	28.51		1
5	HEADGATE TAP		60.00	60.00	SWP SSP	0.97		1
6	GOLD HILL #1		60.00	60.00	SWP SSP	27.85		1
7	GREEN VALLEY	WATSONVILLE	60.00	60.00	SWP SSP	4.74		1
8	CIC TAP		60.00	60.00	SWP	0.13		1
9	DEAN FOODS TAP		60.00	60.00	SWP	0.51		1
10	MONTE RIO	FORT ROSS	60.00	60.00	SWP SSP	14.30		1
11	FORT ROSS	GUALALA	60.00	60.00	SWP SSP	29.76		1
12	SALMON CREEK TAP		60.00	60.00	SWP SSP	10.51		1
13	HALSEY	PLACER	60.00	60.00	SWP SSP	4.94		1
14	MTN QUARRIES TAP		60.00	60.00	SWP SSP	2.63		1
15	AUBURN TAP		60.00	60.00	SWP SSP	0.75		1
16	HAMILTON BRANCH	CHESTER	60.00	60.00	SWP SSP	12.27		1
17	COLLINS PINE TAP		60.00	60.00	SWP	1.00		1
18	HAMMER	COUNTRY CLUB	60.00	60.00	SWP SSP	8.82		1
19	CHCF TAP		115.00	115.00	SWP SSP	3.00		1
20	HAT CREEK #1	PIT #1	60.00	60.00	SWP T SSP	6.08		1
21	HAT CREEK #1	WESTWOOD	60.00	60.00	SWP SSP	55.74		1
22	PIT #1	HAT CREEK #2-BURNEY	60.00	60.00	SWP SSP	12.96		1
23	BURNEY TAP		60.00	60.00	SWP SSP	1.09		1
24	GLENN	DELEVAN	230.00	230.00	T SSP	37.42		1
25	HERDLYN	BALFOUR	60.00	60.00	SWP SSP	20.50		1
26	MIDDLE RIVER TAP		60.00	60.00	SWP SSP	7.02		1
27	MCDONALD TAP		60.00	60.00	SWP SSP	5.88		1
28	MARSH TAP		60.00	60.00	SWP SSP	3.97		1
29	BRIONES TAP		60.00	60.00	SWP SSP	7.00		1
30	BIXLER TAP		60.00	60.00	SWP	0.55		1
31	HILLSDALE JCT	HALF MOON BAY	60.00	60.00	SWP SSP	6.82		1
32	HUMBOLDT BAY	EUREKA	60.00	60.00	SWP SSP	5.61		1
33	HUMBOLDT BAY	HUMBOLDT #1	60.00	60.00	SWP SSP	8.34		1
34	HUMBOLDT BAY	HUMBOLDT #2	60.00	60.00	SWP SSP	6.45		1
35	HUMBOLDT BAY	RIO DELL JCT	60.00	60.00	SWP SSP	18.40		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	EEL RIVER TAP		60.00	60.00	SWP T SSP	2.31		1
2	ARCATA	HUMBOLDT	60.00	60.00	SWP	7.28		1
3	LP FLAKEBOARD TAP		60.00	60.00	SWP	0.51		1
4	HUMBOLDT #1		60.00	60.00	SWP T SSP	11.08		1
5	HUMBOLDT	EUREKA	60.00	60.00	SWP SSP	4.73		1
6	HUMBOLDT	MAPLE CREEK	60.00	60.00	SWP SSP	14.13		1
7	IGNACIO	BOLINAS #1	60.00	60.00	SWP SSP	15.02		1
8	IGNACIO	ALTO	60.00	60.00	SWP SSP	17.79		1
9	IGNACIO	ALTO-SAUSALITO #1	60.00	60.00	SWP T SSP	17.95		1
10	IGNACIO	ALTO-SAUSALITO #2	60.00	60.00	SWP SSP	17.95		1
11	IGNACIO	BOLINAS #2	60.00	60.00	SWP SSP	28.22		1
12	JEFFERSON	HILLSDALE JCT	60.00	60.00	SWP T SSP	14.73		1
13	WATERSHED TAP		60.00	60.00	SWP SSP	0.28		1
14	JEFFERSON	LAS PULGAS	60.00	60.00	SWP SSP	6.00		1
15	MARTIN	SNEATH LANE	60.00	60.00	SWP T SSP	7.19		1
16	CRYSTAL SPRINGS TAP		60.00	60.00	SWP SSP	0.28		1
17	SNEATH LANE	HALF MOON BAY	60.00	60.00	SWP SSP	15.41		1
18	JEFFERSON	STANFORD	60.00	60.00	SWP SSP	7.64		1
19	SLAC TAP		60.00	60.00	SWP	1.41		1
20	KASSON #1		60.00	60.00	SWP SSP	0.19		1
21	KASSON	CARBONA	60.00	60.00	SWP SSP	7.32		1
22	LYOTH TAP		60.00	60.00	SWP	1.34		1
23	CARBONA #2 TAP		60.00	60.00	SWP	5.64		1
24	KASSON	BANTA #1	60.00	60.00	SWP	1.05		1
25	KASSON	LOUISE	60.00	60.00	SWP SSP	8.77		1
26	CALVO TAP		60.00	60.00	SWP	0.54		1
27	EASTSHORE	CERBERUS	115.00	115.00	SSP	0.48		1
28	KESWICK	CASCADE	60.00	60.00	SWP SSP	9.36		1
29	KESWICK	TRINITY	60.00	60.00	SWP SSP	30.42		1
30	KILARC	CEDAR CREEK	60.00	60.00	SWP SSP	13.33		1
31	CLOVER CREEK TAP		60.00	60.00	SWP	0.02		1
32	KILARC	DESCHUTES	60.00	60.00	SWP SSP	27.29		1
33	KILARC	VOLTA TIE	60.00	60.00	T	1.93		1
34	KING CITY	COBURN #1	60.00	60.00	SWP SSP	21.89		1
35	JOLON TAP		60.00	60.00	SWP SSP	15.87		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	KING CITY	COBURN #2	60.00	60.00	SWP SSP	15.79		1
2	LOS COCHES TAP		60.00	60.00	SWP	1.34		1
3	LAKEVILLE #2		60.00	60.00	SWP T SSP	21.62		1
4	LAKEVILLE	PETALUMA C	60.00	60.00	SWP SSP	5.36		1
5	LAKEVILLE #1		60.00	60.00	SWP SSP	11.16		1
6	LAS POSITAS	VASCO	60.00	60.00	SWP SSP	1.50		1
7	LAURELES	OTTER	60.00	60.00	SWP SSP	15.56		1
8	LAYTONVILLE	COVELO	60.00	60.00	SWP SSP	16.09		1
9	LINCOLN	PLEASANT GROVE	115.00	115.00	SWP SSP	7.38		1
10	SIERRA PACIFIC IND TAP		115.00	115.00	SWP	0.06		1
11	LIVERMORE	LAS POSITAS	60.00	60.00	SWP SSP	3.63		1
12	LOCKEFORD	INDUSTRIAL	60.00	60.00	SWP	6.03		1
13	LOCKEFORD	LODI #2	60.00	60.00	SWP SSP	9.52		1
14	INDUSTRIAL TAP		60.00	60.00	SWP	0.97		1
15	VICTOR TAP		60.00	60.00	SSP	0.06		1
16	WOODBIDGE TAP		60.00	60.00	SWP	0.53		1
17	LOCKEFORD	LODI #3	60.00	60.00	SWP SSP	15.42		1
18	MANTECA #1		60.00	60.00	SWP SSP	34.53		1
19	LEE TAP		60.00	60.00	SWP	5.85		1
20	MANTECA	LOUISE	60.00	60.00	SWP SSP	12.53		1
21	GRONEMEYER TAP		60.00	60.00	SWP	0.83		1
22	SCHULTE SW STA	KASSON-MANTECA	115.00	115.00	SWP T SSP	16.58		1
23	MAPLE CREEK	HOOPA	60.00	60.00	SWP SSP	29.13		1
24	SAN MATEO	MARTIN #4	115.00	115.00	SWP SSP	11.64		1
25	MENDOCINO	HARTLEY	60.00	60.00	SWP SSP	23.17		1
26	HARTLEY	CLEARLAKE	60.00	60.00	SWP SSP	6.66		1
27	MENDOCINO	PHILO JCT-HOPLAND	60.00	60.00	SWP SSP	23.50		1
28	MENDOCINO #1		60.00	60.00	SWP SSP	7.48		1
29	MENDOCINO	WILLITS	60.00	60.00	SWP SSP	14.52		1
30	MENDOCINO	WILLITS-FORT BRAGG	60.00	60.00	SWP SSP	43.77		1
31	WEIMAR #1		60.00	60.00	SWP SSP	13.98		1
32	OXBOW TAP		60.00	60.00	SWP	0.15		1
33	MILLBRAE	SNEATH LANE	60.00	60.00	SWP T SSP	6.49		1
34	SAN ANDREAS (CCSF) TAP		60.00	60.00	SWP	0.39		1
35	SAN BRUNO TAP		60.00	60.00	SWP SSP	1.13		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	SNEATH LANE	PACIFICA	60.00	60.00	SWP SSP	3.26		1
2	SANTA PAULA	MILLBRAE	115.00	115.00	SSP	0.09		1
3	MONTA VISTA	BURNS	60.00	60.00	SWP SSP	18.06		1
4	MONTA VISTA	LOS ALTOS	60.00	60.00	SWP SSP	7.13		1
5	MONTA VISTA	LOS GATOS	60.00	60.00	SWP SSP	10.88		1
6	MONTA VISTA	PERMANENTE	60.00	60.00	SWP T SSP	1.19		1
7	PERMANENTE #1 TAP		60.00	60.00	SWP	0.31		1
8	PERMANENTE #2 TAP		60.00	60.00	SWP SSP	0.51		1
9	MONTE RIO	FULTON	60.00	60.00	SWP SSP	22.56		1
10	WOHLER TAP		60.00	60.00	SWP	1.44		1
11	MTN GATE JCT	CASCADE	60.00	60.00	SWP SSP	6.57		1
12	MTN GATE TAP		60.00	60.00	SWP	0.70		1
13	NEWARK	DECOTO	60.00	60.00	SWP T SSP	6.28		1
14	NEWARK	LIVERMORE	60.00	60.00	SWP T SSP	19.05		1
15	NEWARK	VALLECITOS	60.00	60.00	SWP T SSP	12.39		1
16	SUNOL TAP		60.00	60.00	SWP OTHERS	0.08		1
17	NICOLAUS	CATLETT JCT	60.00	60.00	SWP T SSP	20.16		1
18	NICOLAUS	CATLETT JCT	60.00	60.00	SWP T SSP	4.45		1
19	NICOLAUS	CATLETT JCT (12KV)	60.00	60.00	SWP T SSP	14.18		1
20	NICOLAUS	MARYSVILLE	60.00	60.00	SWP SSP	18.74		1
21	NICOLAUS	PLAINFIELD	60.00	60.00	SWP T SSP	30.63		1
22	DISTRICT 1001 TAP		60.00	60.00	SWP	1.47		1
23	NICOLAUS	WILKINS SLOUGH	60.00	60.00	SWP T SSP	42.72		1
24	DISTRICT 1500 TAP		60.00	60.00	SWP SSP	3.61		1
25	TOCALOMA TAP		60.00	60.00	SWP OTHERS	1.03		1
26	OILFIELDS	SARGENT CANYON	60.00	60.00	SWP	2.02		1
27	AERA ENERGY TAP		70.00	60.00	SWP SSP	0.35		1
28	OILFIELDS	SALINAS RIVER	60.00	60.00	SWP	1.46		1
29	YUBA CITY COGEN TAP		60.00	60.00	SWP	0.80		1
30	PALERMO	OROVILLE #1	60.00	60.00	SWP SSP	6.97		1
31	PACIFIC OROVILLE POWER		60.00	60.00	SWP	0.78		1
32	LOUISIANA PACIFIC		60.00	60.00	SWP	0.16		1
33	PALERMO	OROVILLE #2	60.00	60.00	SWP SSP	10.13		1
34	ENCINAL TAP		60.00	60.00	SWP SSP	1.43		1
35	PEASE	HARTER	60.00	60.00	SWP SSP	15.88		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	GREENLEAF #2 TAP		60.00	60.00	SWP	0.62		1
2	PEASE	MARYSVILLE-HARTER	60.00	60.00	SWP SSP	10.31		1
3	PHILO JCT	ELK	60.00	60.00	SWP SSP	37.25		1
4	PIT #1	MCARTHUR	60.00	60.00	SWP SSP	7.30		1
5	PLACER	DEL MAR	60.00	60.00	SWP SSP	10.81		1
6	SIERRA PINES LIMITED		60.00	60.00	SWP	0.40		1
7	POTTER VALLEY	MENDOCINO	60.00	60.00	SWP SSP	10.94		1
8	POTTER VALLEY	WILLITS	60.00	60.00	SWP SSP	13.16		1
9	RADUM	LIVERMORE	60.00	60.00	SWP SSP	4.66		1
10	RIO DELL JCT	BRIDGEVILLE	60.00	60.00	SWP SSP	21.25		1
11	RIO DELL TAP		60.00	60.00	SWP SSP	5.36		1
12	PACIFIC LUMBER (SCOTIA)		60.00	60.00	SWP OTHERS	0.52		1
13	SALADO	CROW CREEK SW STA	60.00	60.00	SWP SSP	3.77		1
14	CROW CREEK SW STA	FRONTIER SOLAR PV	60.00	60.00	SSP	0.02		1
15	CROW CREEK SW STA	NEWMAN	60.00	60.00	SWP SSP	11.14		1
16	STANISLAUS RECOVERY		60.00	60.00	SWP	0.11		1
17	GUSTINE #1 TAP		60.00	60.00	SWP SSP	7.56		1
18	SALADO	NEWMAN #2	60.00	60.00	SWP SSP	21.56		1
19	CROWS LANDING TAP		60.00	60.00	SWP	5.28		1
20	GUSTINE #2 TAP		60.00	60.00	SWP	4.44		1
21	SALINAS	FORT ORD #1	60.00	60.00	SWP T SSP	10.22		1
22	SALINAS	FIRESTONE #1	60.00	60.00	SWP SSP	6.15		1
23	FRESH EXPRESS TAP		60.00	60.00	SWP	0.56		1
24	SALINAS	FIRESTONE #2	60.00	60.00	SWP SSP	13.31		1
25	SALINAS	LAGUNITAS	60.00	60.00	SWP SSP	5.81		1
26	SALINAS	LAURELES	60.00	60.00	SWP SSP	27.46		1
27	SAN MATEO	BAIR	60.00	60.00	T SSP	13.99		1
28	SAN MATEO	HILLSDALE JCT	60.00	60.00	SWP SSP	6.89		1
29	SAN RAMON	RADUM	60.00	60.00	SWP	7.06		1
30	PARKS TAP		60.00	60.00	SWP	0.45		1
31	EAST DUBLIN (BART) TAP		60.00	60.00	SWP	0.04		1
32	SMARTVILLE	CAMP FAR WEST	60.00	60.00	SWP SSP	17.81		1
33	SMARTVILLE	CAMP FAR WEST (12KV)	60.00	60.00	SWP SSP	7.15		1
34	BEALE AFB (WAPA) #2 TAP		60.00	60.00	SWP SSP	0.14		1
35	MONTEZUMA SW STA	BIRDS LANDING SW STA	230.00	230.00	SSP OTHERS	0.54		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	RIO BRAVO (ROCKLIN) TAP		115.00	115.00	SWP	0.40		1
2	SMARTVILLE	MARYSVILLE	60.00	60.00	SWP SSP	20.13		1
3	SMARTVILLE	NICOLAUS #1	60.00	60.00	SWP SSP	29.60		1
4	SMARTVILLE	NICOLAUS #2	60.00	60.00	SWP SSP	30.16		1
5	BEALE AFB (WAPA) #1 TAP		60.00	60.00	SSP	0.11		1
6	SOLEDAD #1		60.00	60.00	SWP SSP	19.38		1
7	GONZALES #1 TAP		60.00	60.00	SWP SSP	0.20		1
8	CHUALAR TAP		60.00	60.00	SWP	1.43		1
9	SOLEDAD #2		60.00	60.00	SWP SSP	18.86		1
10	GONZALES #2 TAP		60.00	60.00	SWP SSP	0.30		1
11	SOLEDAD #3		60.00	60.00	SWP SSP	1.63		1
12	SOLEDAD #4		60.00	60.00	SWP SSP	6.08		1
13	SPAULDING #3	SPAULDING #1	60.00	60.00	SWP SSP	1.09		1
14	SPAULDING	SUMMIT	60.00	60.00	SWP T SSP	19.65		1
15	CISCO GROVE TAP		60.00	60.00	SWP	0.34		1
16	SUTTER HOME SW STA	LOCKEFORD-LODI	60.00	60.00	SWP SSP	29.77		1
17	SUTTER HOME	SUTTER HOME SW STA	60.00	60.00	SSP	0.03		1
18	SUTTER HOME SW STA	STAGG	60.00	60.00	SWP SSP	17.13		1
19	TERMINOUS TAP		60.00	60.00	SWP	3.01		1
20	SEBASTIANI TAP		60.00	60.00	SWP	0.01		1
21	STAGG	COUNTRY CLUB #1	60.00	60.00	SWP SSP	2.43		1
22	STAGG	COUNTRY CLUB #2	60.00	60.00	SWP SSP	2.46		1
23	STAGG	HAMMER	60.00	60.00	SWP SSP	4.25		1
24	STOCKTON A #1		60.00	60.00	SWP T SSP	5.58		1
25	NEWARK-SIERRA		60.00	60.00	SWP	0.29		1
26	STOCKTON A	WEBER #1	60.00	60.00	SWP SSP	13.20		1
27	STOCKTON A	WEBER #2	60.00	60.00	SWP	9.88		1
28	STOCKTON A	WEBER #3	60.00	60.00	SWP SSP	9.82		1
29	SUMIDEN WIRE PRODUCTS		60.00	60.00	SWP	0.19		1
30	OAK PARK TAP		60.00	60.00	SWP SSP	0.87		1
31	STOCKTON	NEWARK	60.00	60.00	SWP T SSP	14.59		1
32	TRINITY	MAPLE CREEK	60.00	60.00	SWP T SSP	55.49		1
33	TULUCAY	NAPA #1	60.00	60.00	SWP T SSP	9.72		1
34	BASALT #1 TAP		60.00	60.00	SWP T	1.18		1
35	CORDELIA #1 TAP		60.00	60.00	SWP SSP	7.69		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	CORDELIA INTERIM		60.00	60.00	SWP SSP	0.36		1
2	CORDELIA #2 TAP		60.00	60.00	SWP SSP	6.87		1
3	TULUCAY	NAPA #2	60.00	60.00	SWP SSP	3.93		1
4	VACA	PLAINFIELD	60.00	60.00	SWP SSP	29.83		1
5	VALLEY SPRINGS #1		60.00	60.00	SWP SSP	27.27		1
6	NEW HOGAN TAP		60.00	60.00	SWP	0.06		1
7	VALLEY SPRINGS	CALAVERAS CEMENT	60.00	60.00	SWP SSP	7.91		1
8	PARDEE #1 TAP		60.00	60.00	SWP	4.33		1
9	VALLEY SPRINGS	MARTELL #1	60.00	60.00	SWP SSP	12.75		1
10	AMFOR TAP		60.00	60.00	SWP	1.08		1
11	CLAY	MARTEL	60.00	60.00	SWP SSP	21.49		1
12	PARDEE #2 TAP		60.00	60.00	SWP	0.09		1
13	BUENA VISTA BIOMASS		60.00	60.00	SWP SSP	1.01		1
14	IONE TAP		60.00	60.00	SWP SSP	4.09		1
15	MULE CREEK TAP		60.00	60.00		0.01		1
16	VASCO	HERDLYN	60.00	60.00	SWP SSP	10.97		1
17	US WINDPOWER TAP		60.00	60.00	SWP	1.52		1
18	VALLEY SPRINGS	CLAY	60.00	60.00	SWP SSP	17.30		1
19	VIEJO	MONTEREY	60.00	60.00	SWP SSP	2.28		1
20	RADUM	VALLECITOS	60.00	60.00	SWP T SSP	10.62		1
21	IUKA TAP		60.00	60.00	SWP	0.49		1
22	VOLTA	DESCHUTES	60.00	60.00	SWP SSP	20.86		1
23	VOLTA	SOUTH	60.00	60.00	SWP SSP	4.86		1
24	WATSONVILLE	SALINAS	60.00	60.00	SWP SSP	28.39		1
25	GRANITE ROCK TAP		60.00	60.00	SWP SSP	2.39		1
26	LAGUNITAS TAP		60.00	60.00	SWP	0.60		1
27	WEBER	FRENCH CAMP #1	60.00	60.00	SWP SSP	6.07		1
28	WEBER	FRENCH CAMP #2	60.00	60.00	SWP T SSP	10.89		1
29	ROBERTSON TAP		60.00	60.00	SWP	0.82		1
30	COGENERATION NATIONAL		60.00	60.00	SWP	0.56		1
31	ROUGH & READY TAP		60.00	60.00	SWP SSP	0.95		1
32	PACIFIC ETHANOL TAP		60.00	60.00	SWP	0.68		1
33	RIO BRAVO TOMATO TAP		115.00	115.00	SWP SSP	0.43		1
34	WEBER	MORMON JCT	60.00	60.00	SWP SSP	17.67		1
35	WEIMAR	HALSEY	60.00	60.00	SWP SSP	6.28		1
36					TOTAL	36,671.97		1,451

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	WEST POINT	VALLEY SPRINGS	60.00	60.00	SWP SSP	21.67		1
2	PINE GROVE TAP		60.00	60.00	SWP SSP	2.67		1
3	LAYTONVILLE	WILLITS	60.00	60.00	SWP SSP	23.14		1
4	GARBERVILLE	LAYTONVILLE	60.00	60.00	SWP SSP	39.99		1
5	WILLOW PASS	CONTRA COSTA	60.00	60.00	SWP T SSP	10.82		1
6	PITTSBURG #2 TAP		60.00	60.00	SWP	1.19		1
7	WIND FARMS		60.00	60.00	SWP	3.75		1
8	ZOND WIND TAP		60.00	60.00	SWP	1.19		1
9	COLUSA JCT #1		60.00	60.00	SWP SSP	16.98		1
10	DEL MONTE	FORT ORD #1	60.00	60.00	SWP SSP	6.13		1
11	MIDDLE FORK #1		60.00	60.00	SWP SSP	9.43		1
12	ELK	GUALALA	60.00	60.00	SWP SSP	29.01		1
13	GARCIA TAP		60.00	60.00	SWP SSP	3.04		1
14	CONTRA COSTA	BALFOUR	60.00	60.00	SWP SSP	11.55		1
15	DU PONT TAP		60.00	60.00	SWP	0.52		1
16	DEL MONTE	FORT ORD #2	60.00	60.00	SWP SSP	5.60		1
17	SALINAS	FORT ORD #2	60.00	60.00	SWP T SSP	10.12		1
18	GLENN #4		60.00	60.00	SWP SSP	12.54		1
19	TABLE MTN	PEACHTON	60.00	60.00	SWP SSP	14.84		1
20	PEACHTON	PEASE	60.00	60.00	SWP SSP	16.34		1
21	GLENN #5		60.00	60.00	SWP SSP	7.41		1
22	COLEMAN HATCHERY TAP		60.00	60.00	SWP SSP	0.56		1
23	ARCO	CARNERAS	70.00	70.00	SWP SSP	18.04		1
24	ARCO	CHOLAME	70.00	70.00	SWP SSP	26.74		1
25	BERRENDA A TAP		70.00	70.00	SWP	2.25		1
26	ANTELOPE TAP		70.00	70.00	SWP SSP	4.33		1
27	BERRENDA C TAP		70.00	70.00	SWP	1.87		1
28	ARCO	POLONIO PASS PP	70.00	70.00	SWP SSP	21.27		1
29	LOST HILLS TAP		70.00	70.00	SWP SSP	2.89		1
30	BADGER HILL TAP		70.00	70.00	SWP	1.56		1
31	ARCO	TULARE LAKE	70.00	70.00	SWP SSP	16.11		1
32	LAS PERILLAS TAP		70.00	70.00	SWP	0.39		1
33	ARCO	TWISSELMAN	70.00	70.00	SWP SSP	6.46		1
34	TEXACO (LOST HILLS) TAP		70.00	70.00	SWP	0.01		1
35	CHEVRON (LOST HILLS)		70.00	70.00	SWP	14.75		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	ATASCADERO	CAYUCOS	70.00	70.00	SWP SSP	11.80		1
2	ATASCADERO	SAN LUIS OBISPO	70.00	70.00	T SSP	15.47		1
3	BORDEN	COPPERMINE	70.00	70.00	SWP SSP	19.96		1
4	RIVER ROCK TAP		70.00	70.00	SWP	1.21		1
5	BORDEN	GLASS	70.00	70.00	SWP SSP	6.62		1
6	BORDEN	MADERA #2	70.00	70.00	SWP SSP	5.81		1
7	CALIFORNIA AVE	KEARNEY	70.00	70.00	SWP	3.20		1
8	CARNERAS	TAFT	70.00	70.00	SWP SSP	34.92		1
9	CELERON TAP		70.00	70.00	SWP	0.04		1
10	LIGHTNER TAP		70.00	70.00	SWP	3.06		1
11	CARUTHERS	LEMOORE NAS-CAMDEN	70.00	70.00	SWP SSP	25.17		1
12	CAYUCOS	CAMBRIA	70.00	70.00	SWP SSP	17.73		1
13	COALINGA #1	COALINGA #2	70.00	70.00	SWP SSP	8.61		1
14	COALINGA COGEN TAP		70.00	70.00	SWP	4.91		1
15	TORNADO TAP		70.00	70.00	SWP	0.06		1
16	DERRICK TAP		70.00	70.00	SWP	0.85		1
17	OIL CITY TAP		70.00	70.00	SWP	0.05		1
18	PENN ZIER TAP		70.00	70.00	SWP	4.99		1
19	COALINGA #1	SAN MIGUEL	70.00	70.00	SWP T SSP	38.01		1
20	COPPERMINE	TIVY VALLEY	70.00	70.00	SWP SSP	24.01		1
21	CORCORAN	ANGIOLA	70.00	70.00	SWP SSP	8.94		1
22	BOSWELL TAP		70.00	70.00	SWP	1.39		1
23	DINUBA	OROSI	70.00	70.00	SWP SSP	9.83		1
24	STONE CORRAL TAP		70.00	70.00	SWP SSP	7.56		1
25	DIVIDE	VANDENBERG #1	70.00	70.00	SWP SSP	6.64		1
26	DIVIDE	VANDENBERG #2	70.00	70.00	SWP SSP	6.57		1
27	DIVIDE	ZACA-LOMPOC (12KV)	70.00	70.00	SWP	10.55		1
28	EXCHEQUER	MARIPOSA	70.00	70.00	SWP T SSP	19.48		1
29	EXCHEQUER	INDIAN FLAT	70.00	70.00	SWP T SSP	29.91		1
30	BRICEBURG		70.00	70.00	SWP SSP	7.78		1
31	GATES	JAYNE SW STA	70.00	70.00	SWP SSP	0.68		1
32	CAMDEN	KINGSBURG	70.00	70.00	SWP SSP	14.93		1
33	FRIANT	COPPERMINE	70.00	70.00	SWP	8.30		1
34	JAYNE SW STA	COALINGA	70.00	70.00	SWP SSP	11.81		1
35	GATES	COALINGA #2	70.00	70.00	SWP SSP	17.26		1
36					TOTAL	36,671.97		1,451

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	GATES	HURON	70.00	70.00	SWP T SSP	4.50		1
2	GATES	TULARE LAKE	70.00	70.00	SWP SSP	18.34		1
3	KETTLEMAN HILLS TAP		70.00	70.00	SWP SSP	1.02		1
4	AVENAL TAP		70.00	70.00	SWP SSP	5.40		1
5	CHEVRON PIPELINE		70.00	70.00	SWP	1.17		1
6	BORDEN	MADERA #1	70.00	70.00	SWP SSP	4.91		1
7	GUERNSEY	HENRIETTA	70.00	70.00	SWP SSP	18.44		1
8	RESERVE OIL TAP		70.00	70.00	SWP	0.58		1
9	ARMSTRONG TAP		70.00	70.00	SWP	0.44		1
10	GWF HANFORD COGEN		70.00	70.00	SWP	0.32		1
11	HAAS	WOODCHUCK	70.00	70.00	SWP SSP	6.79		1
12	HELM	KERMAN	70.00	70.00	SWP SSP	13.25		1
13	FRESNO COGEN (AGRICO)		70.00	70.00	SWP	3.17		1
14	HELM	CRESCENT SW STA	70.00	70.00	SWP SSP	4.92		1
15	HELM	STROUD	70.00	70.00	SWP	7.43		1
16	HENRIETTA	LEMOORE	70.00	70.00	SWP SSP	9.37		1
17	LEPRINO TAP		70.00	70.00	SWP	0.47		1
18	WAUKENA SW STA	CORCORAN	115.00	115.00		2.37		1
19	GWF	HENRIETTA	70.00	70.00	SWP OTHERS	0.12		1
20	HENRIETTA	LEMOORE NAS	70.00	70.00	SWP SSP	1.69		1
21	KENT SW STA	TULARE LAKE	70.00	70.00	SWP T SSP	15.93		1
22	HENRIETTA	KENT SW STA	70.00	70.00	SWP SSP	1.47		1
23	HERDLYN	TRACY	70.00	70.00	SWP	2.06		1
24	KEARNEY	BIOLA	70.00	70.00	SWP SSP	19.14		1
25	KEARNEY	BOWLES	70.00	70.00	SWP SSP	9.29		1
26	KEARNEY	CARUTHERS	70.00	70.00	SWP SSP	12.05		1
27	KEARNEY	KERMAN	70.00	70.00	SWP SSP	10.98		1
28	KERN CANYON	MAGUNDEN-WEEDPATCH	70.00	70.00	SWP T SSP	20.69		1
29	MARICOPA	COPUS	70.00	70.00	SWP SSP	7.86		1
30	KERN	FRUITVALE	70.00	70.00	SWP T	0.16		1
31	KERN	KERN OIL-FAMOSO	70.00	70.00	SWP T SSP	24.69		1
32	CAWELO B TAP		70.00	70.00	SWP	0.40		1
33	KERN	MAGUNDEN	70.00	70.00	SWP T SSP	20.61		1
34	FRUITVALE TAP		70.00	70.00	SWP T	0.12		1
35	EISEN TAP		70.00	70.00	SWP	1.86		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	KERN	OLD RIVER #1	70.00	70.00	SWP T SSP	11.94		1
2	KERN	OLD RIVER #2	70.00	70.00	SWP SSP	23.07		1
3	CARNATION TAP		70.00	70.00	SWP SSP	0.61		1
4	KINGSBURG	LEMOORE	70.00	70.00	SWP T SSP	27.58		1
5	HARDWICK TAP		70.00	70.00	SWP	2.74		1
6	LIVINGSTON	LIVINGSTON JCT	70.00	70.00	SWP SSP	23.36		1
7	LOS BANOS	MERCY SPRINGS SW STA	70.00	70.00	SWP T SSP	14.73		1
8	MERCY SPRINGS SW STA	CANAL-ORO LOMA	70.00	70.00	SWP SSP	23.32		1
9	WRIGHT TAP		70.00	70.00	SWP	1.18		1
10	ARBURUA TAP		70.00	70.00	SWP SSP	3.57		1
11	LOS BANOS	LIVINGSTON JCT-CANAL	70.00	70.00	SWP SSP	14.29		1
12	LOS BANOS	O'NEILL PGP	70.00	70.00	SWP T SSP	3.88		1
13	LOS BANOS	PACHECO	70.00	70.00	SWP T SSP	20.78		1
14	DINOSAUR POINT TAP		70.00	70.00	SWP SSP	2.00		1
15	COPUS	OLD RIVER	70.00	70.00	SWP SSP	19.61		1
16	GARDNER TAP		70.00	70.00	SWP SSP	3.77		1
17	TEXACO BASIC SCHOOL		70.00	70.00	SWP	0.75		1
18	PENTLAND TAP		70.00	70.00	SWP	0.55		1
19	MENDOTA	SAN JOAQUIN-HELM	70.00	70.00	SWP SSP	26.96		1
20	MENDOTA BIOMASS TAP		70.00	70.00	SWP SSP	3.84		1
21	WESTLANDS TAP		70.00	70.00	SWP	1.07		1
22	WESIX TAP		70.00	70.00	SWP SSP	2.51		1
23	GIFFEN TAP		70.00	70.00	SWP SSP	4.95		1
24	MERCED FALLS	EXCHEQUER	70.00	70.00	T SSP	6.51		1
25	MCSWAIN TAP		70.00	70.00	SWP	1.37		1
26	MERCED #1		70.00	70.00	SWP T SSP	39.88		1
27	WILSON	BORDEN #2	230.00	230.00	T SSP	35.37		1
28	MERCED	MERCED FALLS	70.00	70.00	SWP T SSP	20.93		1
29	ORO LOMA	CANAL #1	70.00	70.00	SWP T SSP	24.56		1
30	ORO LOMA	MENDOTA	70.00	70.00	SWP SSP	29.58		1
31	TULE	SPRINGVILLE	70.00	70.00	SWP SSP	15.24		1
32	REEDLEY	DINUBA #1	70.00	70.00	SWP SSP	7.70		1
33	DINUBA ENERGY TAP		70.00	70.00	SWP	3.16		1
34	REEDLEY	OROSI	70.00	70.00	SWP SSP	10.89		1
35	DUNLAP TAP		70.00	70.00	SWP SSP	16.21		1
36					TOTAL	36,671.97		1,451

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	RIO BRAVO HYDRO		70.00	70.00	SWP	0.24		1
2	SAN BERNARD	TEJON	70.00	70.00	SWP SSP	6.96		1
3	SAN LUIS OBISPO	CAYUCOS	70.00	70.00	SWP SSP	23.39		1
4	MUSTANG TAP		70.00	70.00	SWP SSP	0.71		1
5	SAN LUIS OBISPO	SANTA MARIA *	70.00	70.00	SWP SSP	13.33		1
6	SANGER	CALIFORNIA AVE #1	70.00	70.00	SWP SSP	9.23		1
7	SANGER	CALIFORNIA AVE	115.00	115.00	SWP SSP	9.33		1
8	SANGER	REEDLEY	115.00	115.00	SWP SSP	20.42		1
9	SANGER COGEN TAP		115.00	115.00	SWP SSP	0.83		1
10	SCHINDLER	COALINGA #2	70.00	70.00	SWP SSP	17.24		1
11	FIVE POINTS SW STA	HURON-GATES	70.00	70.00	SWP T SSP	19.78		1
12	SCHINDLER	FIVE POINTS SW STA	70.00	70.00	SWP SSP	1.70		1
13	SEMITROPIC	WASCO	70.00	70.00	SWP T SSP	6.32		1
14	MCFARLAND TAP		70.00	70.00	SWP	5.99		1
15	CRESCENT SW STA	SCHINDLER	70.00	70.00	SWP SSP	10.80		1
16	CRESCENT SW STA	STROUD	70.00	70.00	SWP SSP	3.61		1
17	TAFT	CUYAMA #1	70.00	70.00	SWP SSP	19.25		1
18	TAFT	CUYAMA #2	70.00	70.00	SWP SSP	18.75		1
19	TAFT	ELK HILLS	70.00	70.00	SWP SSP	12.39		1
20	TEXACO BUENA VISTA		70.00	70.00	SWP	0.10		1
21	TAFT	MARICOPA	70.00	70.00	SWP T	5.98		1
22	SOLAR TANNEHILL TAP		70.00	70.00	SWP	2.65		1
23	CADET TAP		70.00	70.00	SWP	0.12		1
24	MOCO TAP		70.00	70.00	SWP	1.64		1
25	WASCO	FAMOSO	70.00	70.00	SWP SSP	7.13		1
26	TEJON	LEBEC	70.00	70.00	SWP SSP	13.00		1
27	ROSE TAP		70.00	70.00	SWP	0.31		1
28	GRAPEVINE TAP		70.00	70.00	SWP SSP	0.14		1
29	CASTAIC TAP		70.00	70.00	SWP	0.02		1
30	TIVY VALLEY	REEDLEY	70.00	70.00	SWP	12.30		1
31	WEEDPATCH	SAN BERNARD	70.00	70.00	SWP SSP	9.27		1
32	WEEDPATCH	WELLFIELD	70.00	70.00	SWP SSP	5.89		1
33	SYCAMORE TAP		70.00	70.00	SWP SSP	2.04		1
34	WHEELER RIDGE	LAKEVIEW	70.00	70.00	SWP SSP	7.51		1
35	EMIDIO TAP		70.00	70.00	SWP SSP	3.07		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	KELLEY TAP		70.00	70.00	SWP SSP	2.79		1
2	WHEELER RIDGE	SAN BERNARD	70.00	70.00	SWP SSP	5.88		1
3	WHEELER RIDGE	TEJON	70.00	70.00	SWP T	5.01		1
4	TECUYA TAP		70.00	70.00	SWP SSP	1.91		1
5	WHEELER RIDGE	WEEDPATCH	70.00	70.00	SWP SSP	22.38		1
6	WISHON	COPPERMINE	70.00	70.00	SWP T SSP	19.99		1
7	AUBERRY TAP		70.00	70.00	SWP SSP	2.29		1
8	WISHON	SAN JOAQUIN #3	70.00	70.00	SWP SSP	7.66		1
9	YANKE (NORTH FORK) TAP		70.00	70.00	SWP	0.42		1
10	BIOLA	GLASS-MADERA	70.00	70.00	SWP SSP	18.83		1
11	CANANDAIGUA WINERY		70.00	70.00	SWP	0.29		1
12	BONITA TAP		70.00	70.00	SWP SSP	3.04		1
13	EL PECO TAP		70.00	70.00	SWP	3.02		1
14	CORCORAN	GUERNSEY	70.00	70.00	SWP SSP	13.49		1
15	KEARNEY TIE		70.00	70.00	SWP T	0.15		1
16	KEARNEY ALTERNATE TIE		70.00	70.00	SWP T	0.30		1
17	SAN MIGUEL	PASO ROBLES	70.00	70.00	SWP SSP	9.92		1
18	PASO ROBLES	TEMPLETON	70.00	70.00	SWP SSP	4.90		1
19	TEMPLETON	ATASCADERO	70.00	70.00	SWP SSP	8.82		1
20	ATLANTIC	PLEASANT GROVE #2	115.00	115.00	SWP SSP	5.36		1
21	GOLD HILL	CLARKSVILLE	115.00	115.00	T SSP	5.77		1
22	VALLEY SPRINGS #2		60.00	60.00	SWP SSP	25.65		1
23	LOCKEFORD #1		60.00	60.00	SWP SSP	12.85		1
24	STANDARD #1 & #2 (12KV)		60.00	60.00	T	4.16		1
25	A	Y #1 (UNDERGROUND IDLE)			N/A	0.35		1
26	SOBRANTE	R #1	115.00		N/A	0.33		1
27	SOBRANTE	R #1	115.00		N/A	0.33		1
28	SOBRANTE	R #2	115.00		N/A	0.30		1
29	SOBRANTE	R #2	115.00		N/A	0.30		1
30	ZA	1	230.00	230.00	N/A	3.41		1
31	C	X #3	115.00	115.00	N/A	3.67		1
32	H	P #4	115.00	115.00	N/A	5.16		1
33	LAKEVILLE	SONOMA #1	115.00	115.00	N/A	0.55		1
34	NORTH DUBLIN	CAYETANO	230.00	230.00	N/A	2.81		1
35	DEL MAR	ATLANTIC #1	60.00	60.00	N/A	1.18		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	JEFFERSON	MARTIN	230.00	230.00	N/A	24.40		1
2	A	P #1	115.00	115.00	N/A	2.46		1
3	LONE TREE	CAYETANO	230.00	230.00	N/A	2.30		1
4	NEWARK	LOS ESTEROS	230.00	230.00	N/A	2.75		1
5	LOS ESTEROS	METCALF	230.00	230.00	N/A	2.73		1
6	VINEYARD	NEWARK	230.00	230.00	N/A	5.94		1
7	NORTH DUBLIN	VINEYARD	230.00	230.00	N/A	11.07		1
8	A	H-W #1	115.00	115.00	N/A	4.95		1
9	A	X #1	115.00	115.00	N/A	2.67		1
10	A	Y #1	115.00	115.00	N/A	3.33		1
11	A	Y #2	115.00	115.00	N/A	2.85		1
12	H	P #1	115.00	115.00	N/A	3.80		1
13	A	H-W #2	115.00	115.00	N/A	5.06		1
14	H	Y #1	115.00	115.00	N/A	7.23		1
15	H	P #3	115.00	115.00	N/A	3.59		1
16	P	X #1	115.00	115.00	N/A	4.01		1
17	P	X #2 (UNDERGROUND)	115.00	115.00	N/A	3.95		1
18	X	Y #1	115.00	115.00	N/A	0.57		1
19	C	L #1	115.00	115.00	N/A	1.10		1
20	C	X #2	115.00	115.00	N/A	3.38		1
21	D	L #1	115.00	115.00	N/A	2.31		1
22	SOBRANTE	R #1	115.00	115.00	N/A	4.16		1
23	SOBRANTE	R #2	115.00	115.00	N/A	4.11		1
24	K	D #1	115.00	115.00	N/A	2.44		1
25	K	D #2	115.00	115.00	N/A	2.57		1
26	EBMUD TAP		115.00	115.00	N/A	0.94		1
27	SAN MATEO	MARTIN #4	115.00	115.00	N/A	0.21		1
28	SAN MATEO	MARTIN #3	115.00	115.00	N/A	0.21		1
29	EAST GRAND	SAN MATEO	115.00	115.00	N/A	0.22		1
30	MARTIN	MILLBRAE #1	115.00	115.00	N/A	0.22		1
31	MARTIN	SF AIRPORT	115.00	115.00	N/A	0.23		1
32	SAN MATEO	MARTIN #6	115.00	115.00	N/A	0.23		1
33	COOLEY LANDING	STANFORD	60.00	60.00	N/A	1.59		1
34	JEFFERSON	STANFORD	60.00	60.00	N/A	1.52		1
35	TRIMBLE	SAN JOSE B	115.00	115.00	N/A	1.11		1
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS

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	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	KIFER	FMC	115.00	115.00	N/A	1.11		1
2	SAN MATEO	MARTIN	230.00	230.00	N/A	13.00		1
3	H	Z #1	230.00	230.00	N/A	6.92		1
4	H	Z #2	230.00	230.00	N/A	6.96		1
5	FIGARDEN #1 TAP		230.00	230.00	N/A	0.85		1
6	FULTON	LAKEVILLE	230.00	230.00	N/A	1.19		1
7	GEYSERS #9	LAKEVILLE	230.00	230.00	N/A	1.24		1
8	JEFFERSON	LAS PULGAS	60.00	60.00	N/A	0.18		1
9	NEWARK	APPLIED MATERIALS	115.00	115.00	N/A	0.74		1
10	APPLIED MATERIALS	BRITTON	115.00	115.00	N/A	0.74		1
11	BORDEN	GLASS; XLPE; 70 KV	70.00	70.00	N/A	0.39		1
12	STELLING	MONTA VISTA	115.00	115.00	N/A	1.14		1
13	MONTA VISTA	WOLFE	115.00	115.00	N/A	1.12		1
14	PITTSBURG	LOS MEDANOS #1	115.00	115.00	N/A	0.88		1
15	PITTSBURG	LOS MEDANOS #2	115.00	115.00	N/A	0.89		1
16	FIGARDEN #2 TAP		230.00	230.00	N/A	0.83		1
17								
18								
19								
20								
21								
22	Summary of lines							
23	listed individually above							
24	Towers & Poles		500.00			1,328.00		
25			230.00			5,334.00		
26			115.00			6,071.00		
27			70.00			1,545.00		
28			60.00			3,882.00		
29								
30	Other Underground		230.00			86.00		
31	Transmission Lines		115.00			85.00		
32			70.00					
33			60.00			5.00		
34								
35	Transmission Roads							
36					TOTAL	36,671.97		1,451

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
477 - ACSS - SING								1
1113 - AAC - SING								2
795 - ACSR - SING								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
477 - ACSS - SING								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
1113 - AAC - SING								11
477 - ACSS - SING								12
477 - ACSS - SING								13
715.5 - AAC - SIN								14
1113 - AAC - SING								15
715.5 - AAC - SIN								16
1113 - AAC - SING								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
397.5 - AAC - SIN								20
397.5 - ACSR - SI								21
								22
1113 - AAC - SING								23
1113 - AAC - SING								24
477 - ACSS - SING								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
336.4 - AAC - SIN								28
4/0 - ACSR - SING								29
3/0 - CU - SINGLE								30
715.5 - AAC - SIN								31
3/0 - CU - SINGLE								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
477 - ACSS - SING								5
795 - ACSR - SING								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
4/0 - AAC - SINGL								9
336.4 - AAC - SIN								10
715.5 - AAC - SIN								11
1113 - AAC - SING								12
								13
250 - CU - SINGLE								14
715.5 - AAC - SIN								15
4/0 - AAC - SINGL								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
1113 - AAC - SING								21
4/0 - AAC - SINGL								22
266.8 - AAC - SIN								23
250 - CU - SINGLE								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
1113 - AAC - SING								27
4/0 - AAC - SINGL								28
1113 - AAC - SING								29
397.5 - ACSR - SI								30
4/0 - ACSR - SING								31
397.5 - AAC - SIN								32
250 - CU - SINGLE								33
477 - ACSS - SING								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
397.5 - AAC - SIN								4
397.5 - AAC - SIN								5
477 - ACSS - SING								6
397.5 - ACSR - SI								7
4/0 - ACSR - SING								8
397.5 - ACSR - SI								9
397.5 - ACSR - SI								10
								11
477 - ACSS - SING								12
715.5 - AAC - SIN								13
954 - AAC - SINGL								14
3/4 - CU-STEEL -								15
715.5 - AAC - SIN								16
397.5 - ACSR - SI								17
3/4 - CU-STEEL -								18
397.5 - ACSR - SI								19
397.5 - ACSR - SI								20
397.5 - ACSR - SI								21
795 - ACSS - SING								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
4/0 - AAC - SINGL								25
477 - ACSS - SING								26
477 - ACSS - BUND								27
715.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - PAR								31
397.5 - AAC - SIN								32
4/0 - AAC - SINGL								33
397.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
477 - ACSS - SING								1
795 - ACSS - SING								2
715.5 - AAC - SIN								3
266.8 - AAC - SIN								4
715.5 - AAC - SIN								5
1113 - AAC - SING								6
715.5 - AAC - SIN								7
477 - ACSS - SING								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
397.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
4/0 - CU - SINGLE								13
397.5 - AAC - SIN								14
477 - ACSS - SING								15
477 - ACSS - SING								16
715.5 - AAC - SIN								17
397.5 - ACSR - SI								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - CU - SINGLE								22
4/0 - AAC - SINGL								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
2/0 - CU - SINGLE								28
715.5 - AAC - SIN								29
2/0 - CU - SINGLE								30
1113 - AAC - SING								31
1113 - AAC - SING								32
1113 - AAC - SING								33
1113 - AAC - SING								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
715.5 - AAC - SIN								1
1113 - AAC - SING								2
4/0 - AAC - SINGL								3
477 - ACSS - SING								4
715.5 - AAC - SIN								5
477 - ACSS - SING								6
477 - ACSS - SING								7
1113 - AAC - SING								8
397.5 - AAC - SIN								9
397.5 - ACSR - SI								10
4/0 - ACSR - SING								11
4/0 - ACSR - SING								12
397.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
4/0 - AAC - SINGL								15
4/0 - ACSR - SING								16
397.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
1113 - AAC - SING								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
266.8 - AAC - SIN								29
1113 - AAC - SING								30
715.5 - AAC - SIN								31
715.5 - AAC - SIN								32
								33
715.5 - AAC - SIN								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
250 - CU - PARALL								4
4/0 - AAC - SINGL								5
4/0 - AAC - SINGL								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
795 - ACSS - SING								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
1113 - AAC - SING								19
397.5 - AAC - SIN								20
4/0 - AAC - SINGL								21
4/0 - AAC - SINGL								22
477 - ACSS - SING								23
477 - ACSS - SING								24
715.5 - AAC - SIN								25
								26
477 - ACSS - SING								27
477 - ACSS - SING								28
715.5 - AAC - SIN								29
1113 - AAC - SING								30
4/0 - AAC - SINGL								31
397.5 - AAC - SIN								32
397.5 - AAC - SIN								33
715.5 - AAC - SIN								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
397.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
4/0 - AAC - SINGL								5
715.5 - AAC - BUN								6
715.5 - AAC - BUN								7
477 - ACSS - SING								8
477 - ACSS - SING								9
477 - ACSS - SING								10
1113 - AAC - SING								11
4/0 - AAC - SINGL								12
477 - ACSS - SING								13
4/0 - AAC - SINGL								14
4/0 - AAC - SINGL								15
397.5 - AAC - SIN								16
397.5 - AAC - SIN								17
397.5 - AAC - SIN								18
477 - ACSS - SING								19
477 - ACSS - SING								20
477 - ACSS - SING								21
397.5 - AAC - SIN								22
715.5 - AAC - SIN								23
								24
715.5 - AAC - SIN								25
397.5 - AAC - SIN								26
4/0 - AAC - SINGL								27
1113 - AAC - BUND								28
1113 - AAC - SING								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
715.5 - AAC - SIN								32
397.5 - AAC - SIN								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1113 - AAC - SING								1
477 - ACSS - SING								2
477 - ACSS - SING								3
477 - ACSS - SING								4
477 - ACSS - SING								5
477 - ACSS - SING								6
4/0 - AAC - SINGL								7
477 - ACSS - SING								8
477 - ACSS - SING								9
795 - ACSS - SING								10
715.5 - AAC - SIN								11
397.5 - ACSR - SI								12
4/0 - ACSR - SING								13
397.5 - AAC - SIN								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
397.5 - AAC - SIN								17
4/0 - ACSR - SING								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
266.8 - AAC - SIN								23
1113 - AAC - SING								24
397.5 - AAC - SIN								25
397.5 - AAC - SIN								26
715.5 - AAC - SIN								27
397.5 - AAC - SIN								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
397.5 - AAC - SIN								31
477 - ACSS - SING								32
397.5 - AAC - SIN								33
477 - ACSS - SING								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
477 - ACSS - SING								1
715.5 - AAC - SIN								2
795 - ACSS - SING								3
795 - ACSS - SING								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
397.5 - AAC - SIN								7
477 - ACSS - SING								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
477 - ACSS - SING								11
4/0 - AAC - SINGL								12
4/0 - AAC - SINGL								13
1113 - ACSS - SIN								14
1113 - ACSS - SIN								15
715.5 - AAC - SIN								16
1113 - AAC - SING								17
250 - CU - SINGLE								18
336.4 - AAC - SIN								19
4/0 - AAC - SINGL								20
715.5 - AAC - SIN								21
477 - ACSS - SING								22
477 - ACSS - SING								23
336.4 - AAC - SIN								24
1113 - AAC - SING								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
477 - ACSS - SING								28
715.5 - AAC - SIN								29
477 - ACSS - SING								30
715.5 - AAC - SIN								31
3/0 - CU - SINGLE								32
3/0 - CU - SINGLE								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
397.5 - AAC - SIN								8
1113 - AAC - SING								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
477 - ACSS - SING								12
477 - ACSS - SING								13
1 - UNKNOWN -								14
477 - ACSS - SING								15
266.8 - AAC - SIN								16
477 - ACSS - SING								17
266.8 - AAC - SIN								18
477 - ACSS - SING								19
477 - ACSS - SING								20
477 - ACSS - SING								21
2/0 - CU - SINGLE								22
715.5 - AAC - SIN								23
477 - ACSS - SING								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
1113 - AAC - BUND								28
477 - ACSS - SING								29
397.5 - AAC - SIN								30
477 - ACSS - SING								31
477 - ACSS - SING								32
477 - ACSS - SING								33
477 - ACSS - SING								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
715.5 - AAC - SIN								1
715.5 - AAC - SIN								2
4/0 - AAC - SINGL								3
477 - ACSS - SING								4
397.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
3/0 - CU - SINGLE								7
477 - ACSS - SING								8
1113 - AAC - SING								9
4/0 - CU - SINGLE								10
715.5 - AAC - SIN								11
665-T16 -								12
715.5 - AAC - SIN								13
665-T16 -								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - BUN								18
1 - UNKNOWN -								19
4/0 - ACSR - SING								20
715.5 - AAC - SIN								21
3/0 - CU - PARALL								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
715.5 - AAC - SIN								28
397.5 - AAC - SIN								29
452.3 - ACAR - SI								30
1113 - AAC - SING								31
4/0 - AAC - SINGL								32
1113 - AAC - SING								33
477 - ACSS - SING								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
397.5 - AAC - SIN								1
477 - ACSS - SING								2
4/0 - AAC - SINGL								3
4/0 - AAC - SINGL								4
4/0 - AAC - SINGL								5
397.5 - ACSR - SI								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
715.5 - AAC - SIN								11
397.5 - AAC - SIN								12
4/0 - AAC - SINGL								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
477 - ACSS - SING								17
1 - UNKNOWN -								18
715.5 - AAC - BUN								19
477 - ACSS - SING								20
715.5 - AAC - BUN								21
715.5 - AAC - SIN								22
4/0 - AAC - SINGL								23
397.5 - AAC - SIN								24
2300 - AAC - BUND								25
2300 - AAC - BUND								26
715.5 - AAC - SIN								27
477 - ACSS - SING								28
4/0 - AAC - SINGL								29
4/0 - AAC - SINGL								30
477 - ACSS - SING								31
4/0 - AAC - SINGL								32
477 - ACSS - SING								33
4/0 - AAC - SINGL								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
477 - ACSS - SING								1
715.5 - AAC - SIN								2
2/0 - CU - SINGLE								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
477 - ACSS - SING								10
477 - ACSS - SING								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
397.5 - AAC - SIN								14
715.5 - AAC - SIN								15
4/0 - CU - SINGLE								16
397.5 - ACSR - SI								17
1113 - AAC - SING								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
336.4 - AAC - SIN								22
397.5 - ACSR - SI								23
4/0 - CU - SINGLE								24
715.5 - AAC - SIN								25
477 - ACSS - SING								26
477 - ACSS - SING								27
715.5 - AAC - SIN								28
1113 - AAC - SING								29
397.5 - AAC - SIN								30
397.5 - AAC - SIN								31
1113 - AAC - SING								32
715.5 - AAC - SIN								33
4/0 - AAC - SINGL								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
4/0 - CU - SINGLE								2
4/0 - CU - SINGLE								3
397.5 - AAC - SIN								4
4/0 - AAC - SINGL								5
397.5 - AAC - SIN								6
1113 - AAC - SING								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
250 - CU - PARALL								10
1113 - AAC - SING								11
477 - ACSS - SING								12
1113 - AAC - SING								13
250 - CU - PARALL								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
477 - ACSS - SING								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
2/0 - CU - SINGLE								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
2/0 - CU - SINGLE								28
2/0 - CU - SINGLE								29
2/0 - CU - SINGLE								30
477 - ACSS - SING								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
397.5 - AAC - SIN								34
477 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
4/0 - AAC - SINGL								1
477 - ACSS - SING								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
336.4 - AAC - SIN								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
477 - ACSS - SING								11
715.5 - AAC - SIN								12
2/0 - CU - SINGLE								13
4/0 - AAC - SINGL								14
								15
477 - ACSS - SING								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
954 - ACSS - SING								19
477 - ACSS - SING								20
4/0 - AAC - SINGL								21
4/0 - AAC - SINGL								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
477 - ACSS - SING								26
4/0 - AAC - SINGL								27
715.5 - AAC - SIN								28
1 - UNKNOWN -								29
715.5 - AAC - BUN								30
336.4 - ACAR - SI								31
397.5 - ACSR - SI								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 - AAC - SIN								1
4/0 - ACSR - SING								2
477 - ACSS - SING								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
477 - ACSS - SING								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
715.5 - AAC - SIN								11
397.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
715.5 - AAC - SIN								16
266.8 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
4/0 - AAC - SINGL								20
715.5 - AAC - SIN								21
4/0 - ACSR - SING								22
397.5 - ACSR - SI								23
4/0 - ACSR - SING								24
715.5 - AAC - SIN								25
954 - AAC - SINGL								26
1431 - AAC - SING								27
1113 - AAC - SING								28
250 - CU - SINGLE								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
477 - ACSS - SING								32
477 - ACSS - SING								33
477 - ACSS - SING								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
477 - ACSS - SING								1
715.5 - AAC - SIN								2
477 - ACSS - SING								3
477 - ACSS - SING								4
715.5 - AAC - SIN								5
336.4 - AAC - SIN								6
1 - UNKNOWN -								7
477 - ACSS - SING								8
1113 - AAC - SING								9
1113 - AAC - SING								10
804.5 - ACSR - SI								11
954 - AAC - SINGL								12
1113 - AAC - SING								13
954 - ACSS - SING								14
954 - ACSR - SING								15
954 - ACSR - SING								16
954 - ACSS - SING								17
1113 - AAC - SING								18
4/0 - CU - SINGLE								19
4/0 - CU - SINGLE								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
1113 - AAC - SING								23
1113 - AAC - SING								24
1113 - AAC - SING								25
795 - ACSS - SING								26
954 - AAC - SINGL								27
795 - ACSR - SING								28
1113 - AAC - SING								29
1113 - AAC - SING								30
1113 - ACSS - SIN								31
1113 - AAC - SING								32
1113 - AAC - SING								33
1113 - AAC - SING								34
954 - ACSS - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 - ACSS - SING								1
954 - ACSS - SING								2
1113 - AAC - SING								3
1113 - AAC - SING								4
1113 - AAC - SING								5
954 - ACSS - SING								6
1113 - AAC - SING								7
643.7 - HOLO-CU -								8
643.7 - HOLO-CU -								9
954 - AAC - SINGL								10
1113 - AAC - SING								11
954 - AAC - SINGL								12
795 - ACSR - SING								13
1113 - AAC - SING								14
1113 - AAC - SING								15
1113 - AAC - SING								16
795 - ACSR - SING								17
1113 - AAC - BUND								18
954 - ACSS - SING								19
1113 - AAC - SING								20
518 - ACSR - SING								21
1113 - AAC - SING								22
1113 - AAC - SING								23
1113 - ACSS - SIN								24
1113 - ACSS - SIN								25
795 - ACSR - SING								26
795 - ACSR - SING								27
1113 - AAC - SING								28
1113 - AAC - SING								29
1113 - AAC - SING								30
1113 - AAC - SING								31
2300 - AAC - BUND								32
2300 - AAC - BUND								33
1431 - AAC - SING								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1431 - AAC - SING								1
1113 - AAC - SING								2
954 - AAC - SINGL								3
1113 - AAC - SING								4
1113 - AAC - SING								5
1113 - AAC - SING								6
1113 - AAC - BUND								7
1113 - AAC - BUND								8
954 - AAC - SINGL								9
1113 - ACSS - SIN								10
1272 - ACSR - BUN								11
1272 - ACSR - BUN								12
1113 - AAC - SING								13
795 - ACSR - SING								14
958-T16 -								15
2300 - AAC - BUND								16
1113 - AAC - SING								17
954 - ACSS - SING								18
1113 - AAC - SING								19
2300 - AAC - BUND								20
1113 - AAC - SING								21
2156 - ACSS - SIN								22
1113 - AAC - SING								23
1113 - AAC - SING								24
1113 - AAC - SING								25
1113 - ACSS - SIN								26
1113 - AAC - SING								27
1113 - AAC - SING								28
1113 - AAC - SING								29
795 - ACSR - SING								30
1113 - AAC - SING								31
1113 - AAC - SING								32
1113 - AAC - SING								33
1113 - AAC - SING								34
795 - ACSS - BUND								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
795 - ACSR - PARA								1
1113 - AAC - SING								2
2300 - AAC - BUND								3
2300 - AAC - BUND								4
2300 - AAC - BUND								5
954 - ACSS - SING								6
954 - ACSS - SING								7
1113 - AAC - SING								8
1113 - AAC - BUND								9
1113 - AAC - SING								10
1113 - AAC - SING								11
1113 - AAC - SING								12
1113 - AAC - SING								13
1113 - AAC - BUND								14
1113 - AAC - SING								15
1113 - AAC - SING								16
1113 - AAC - SING								17
1113 - AAC - SING								18
1113 - AAC - SING								19
1113 - AAC - BUND								20
1113 - AAC - SING								21
1113 - AAC - SING								22
1113 - AAC - SING								23
1113 - AAC - SING								24
1113 - AAC - SING								25
954 - ACSS - SING								26
954 - ACSS - SING								27
1113 - AAC - SING								28
954 - ACSS - SING								29
954 - ACSS - SING								30
1113 - AAC - SING								31
1113 - AAC - SING								32
954 - ACSR - SING								33
1113 - AAC - SING								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
1113 - AAC - SING								1
1113 - AAC - SING								2
1113 - AAC - SING								3
1113 - AAC - SING								4
1113 - AAC - SING								5
1113 - AAC - SING								6
1113 - AAC - BUND								7
795 - ACSR - PARA								8
1113 - AAC - SING								9
795 - ACSS - SING								10
1113 - ACSS - SIN								11
1113 - ACSS - SIN								12
518 - ACSR - SING								13
795 - ACSR - SING								14
795 - ACSR - SING								15
518 - ACSR - SING								16
1113 - AAC - SING								17
1113 - AAC - SING								18
1113 - AAC - SING								19
1113 - AAC - SING								20
795 - ACSR - SING								21
1113 - AAC - SING								22
518 - ACSR - SING								23
795 - ACSR - SING								24
795 - ACSR - SING								25
518 - ACSR - SING								26
1113 - AAC - SING								27
954 - ACSS - SING								28
954 - ACSS - SING								29
1113 - AAC - SING								30
1113 - AAC - SING								31
1113 - AAC - SING								32
954 - ACSS - SING								33
1113 - ACSS - SIN								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2300 - AAC - BUND								1
1113 - AAC - SING								2
1113 - AAC - SING								3
2300 - AAC - BUND								4
795 - ACSR - SING								5
2300 - AAC - SING								6
2300 - AAC - SING								7
1113 - AAC - BUND								8
1113 - AAC - SING								9
795 - ACSR - SING								10
1113 - AAC - SING								11
1113 - AAC - SING								12
795 - ACSR - SING								13
795 - ACSR - SING								14
500 - CU - SINGLE								15
1113 - AAC - SING								16
2300 - AAC - BUND								17
1113 - AAC - SING								18
795 - ACSS - SING								19
795 - ACSS - SING								20
954 - ACSS - SING								21
2300 - AAC - BUND								22
954 - ACSS - BUND								23
954 - ACSS - SING								24
954 - ACSS - SING								25
795 - ACSR - PARA								26
2300 - AAC - BUND								27
1113 - AAC - SING								28
1113 - AAC - SING								29
1113 - AAC - SING								30
954 - AAC - SINGL								31
1113 - ACSS - SIN								32
1113 - ACSS - SIN								33
1113 - ACSS - SIN								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
1113 - ACSS - SIN								1
1113 - AAC - SING								2
1113 - AAC - SING								3
1113 - AAC - SING								4
954 - ACSS - SING								5
1113 - AAC - SING								6
795 - ACSS - SING								7
954 - ACSR - SING								8
954 - AAC - SINGL								9
1113 - AAC - SING								10
1113 - AAC - SING								11
1113 - AAC - SING								12
954 - ACSS - SING								13
954 - AAC - SINGL								14
1113 - AAC - SING								15
954 - ACSS - SING								16
954 - ACSS - BUND								17
2300 - AAC - BUND								18
2300 - AAC - BUND								19
2300 - AAC - BUND								20
2300 - AAC - BUND								21
2300 - AAC - BUND								22
2300 - AAC - BUND								23
2300 - AAC - BUND								24
2300 - AAC - BUND								25
2300 - AAC - BUND								26
2300 - AAC - BUND								27
2300 - AAC - BUND								28
2300 - AAC - BUND								29
2300 - AAC - BUND								30
2300 - AAC - BUND								31
2300 - AAC - BUND								32
2300 - AAC - BUND								33
2300 - AAC - BUND								34
2300 - AAC - BUND								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2300 - AAC - BUND								1
2300 - AAC - BUND								2
2300 - AAC - BUND								3
2/0 - CU - SINGLE								4
1113 - AAC - BUND								5
1113 - AAC - BUND								6
1113 - AAC - SING								7
1113 - ACSS - SIN								8
715.5 - AAC - SIN								9
1113 - ACSS - SIN								10
477 - ACSS - SING								11
477 - ACSS - SING								12
477 - ACSS - SING								13
477 - ACSS - SING								14
477 - ACSS - SING								15
4/0 - AAC - SINGL								16
4/0 - AAC - SINGL								17
4/0 - ACSR - SING								18
4/0 - AAC - SINGL								19
								20
4/0 - AAC - SINGL								21
1/0 - ACSR - SING								22
4/0 - AAC - SINGL								23
4/0 - AAC - SINGL								24
1/0 - CU - SINGLE								25
4/0 - ACSR - SING								26
397.5 - ACSR - SI								27
397.5 - ACSR - SI								28
								29
397.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
1/0 - ACSR - SING								32
715.5 - AAC - SIN								33
4/0 - AAC - SINGL								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
336.4 - AAC - SIN								1
715.5 - AAC - SIN								2
336.4 - AAC - SIN								3
4/0 - AAC - SINGL								4
336.4 - AAC - SIN								5
3/0 - CU - SINGLE								6
3/0 - CU - SINGLE								7
1/0 - ACSR - SING								8
4/0 - AAC - SINGL								9
250 - CU - SINGLE								10
715.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
4/0 - AAC - SINGL								13
715.5 - AAC - SIN								14
397.5 - AAC - SIN								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
1 - CU - SINGLE 2								19
715.5 - AAC - SIN								20
1113 - AAC - BUND								21
4 - ACSR - SINGLE								22
4 - CU - SINGLE 4								23
2/0 - CU - SINGLE								24
4/0 - CU - SINGLE								25
477 - ACSS - SING								26
715.5 - AAC - SIN								27
4/0 - CU - SINGLE								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
397.5 - AAC - SIN								32
715.5 - AAC - SIN								33
4/0 - CU - SINGLE								34
4/0 - CU - SINGLE								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
336.4 - AAC - SIN								1
336.4 - AAC - SIN								2
4/0 - CU - SINGLE								3
4/0 - AAC - SINGL								4
715.5 - AAC - BUN								5
2 - ACSR - SINGLE								6
1/0 - ACSR - SING								7
715.5 - AAC - SIN								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
1431 - AAC - SING								12
336.4 - AAC - SIN								13
4/0 - AAC - SINGL								14
715.5 - AAC - SIN								15
1/0 - ACSR - SING								16
4/0 - CU - SINGLE								17
250 - CU - SINGLE								18
4/0 - ACSR - SING								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
2/0 - CU - SINGLE								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
2 - CU - SINGLE								25
350 - AAC - SINGL								26
2 - ACSR - SINGLE								27
350 - AAC - SINGL								28
715.5 - AAC - SIN								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
4/0 - AAC - SINGL								32
518 - ACSR - SING								33
715.5 - AAC - SIN								34
4/0 - CU - SINGLE								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2 - ACSR - SINGLE								1
4/0 - ACSR - SING								2
397.5 - ACSR - SI								3
4/0 - ACAR - SING								4
4/0 - ACAR - SING								5
4/0 - AAC - SINGL								6
4/0 - AAC - SINGL								7
4/0 - AAC - SINGL								8
4/0 - AAC - SINGL								9
4/0 - AAC - SINGL								10
1 - CU - SINGLE								11
715.5 - AAC - SIN								12
336.4 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
336.4 - AAC - SIN								16
336.4 - AAC - SIN								17
336.4 - AAC - SIN								18
397.5 - AAC - SIN								19
715.5 - AAC - SIN								20
4/0 - AAC - SINGL								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
4/0 - ACSR - SING								24
397.5 - ACSR - SI								25
477 - ACSS - SING								26
477 - ACSS - SING								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
2/0 - CU - SINGLE								30
471 - AAC - SINGL								31
715.5 - AAC - SIN								32
715.5 - AAC - SIN								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
715.5 - AAC - SIN								1
2 - ACSR - SINGLE								2
1 - CU - BUNDLE 3								3
1 - CU - SINGLE 3								4
4/0 - AAC - SINGL								5
4/0 - CU - SINGLE								6
397.5 - AAC - SIN								7
397.5 - AAC - SIN								8
397.5 - AAC - SIN								9
715.5 - AAC - SIN								10
397.5 - AAC - SIN								11
4/0 - AAC - SINGL								12
397.5 - AAC - SIN								13
397.5 - AAC - SIN								14
4/0 - AAC - SINGL								15
4/0 - ACSR - SING								16
2 - ACSR - SINGLE								17
477 - ACSS - SING								18
397.5 - AAC - SIN								19
1/0 - ACSR - SING								20
4/0 - CU - SINGLE								21
3/0 - CU - SINGLE								22
1/0 - ACSR - SING								23
954 - AAC - SINGL								24
1 - CU - SINGLE 4								25
4/0 - AAC - SINGL								26
1/0 - ACSR - SING								27
1/0 - ACSR - SING								28
4/0 - AAC - SINGL								29
4/0 - AAC - SINGL								30
397.5 - AAC - SIN								31
715.5 - AAC - SIN								32
336.4 - AAC - SIN								33
1113 - AAC - SING								34
1113 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
397.5 - AAC - SIN								3
715.5 - AAC - SIN								4
715.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
715.5 - AAC - SIN								7
477 - ACSS - SING								8
4/0 - AAC - SINGL								9
477 - ACSS - SING								10
2 - ACSR - SINGLE								11
477 - ACSS - SING								12
4/0 - AAC - SINGL								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
4/0 - AAC - SINGL								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
397.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - AAC - SINGL								22
397.5 - AAC - SIN								23
715.5 - AAC - SIN								24
715.5 - AAC - SIN								25
2 - ACSR - SINGLE								26
397.5 - AAC - SIN								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
1/0 - ACSR - SING								30
								31
1/0 - ACSR - SING								32
1/0 - ACSR - SING								33
4/0 - AAC - SINGL								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
336.4 - AAC - SIN								1
4/0 - AAC - SINGL								2
397.5 - AAC - SIN								3
250 - CU - SINGLE								4
397.5 - AAC - SIN								5
715.5 - AAC - SIN								6
4/0 - AAC - SINGL								7
715.5 - AAC - SIN								8
1113 - AAC - SING								9
4/0 - AAC - SINGL								10
715.5 - AAC - SIN								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
4/0 - AAC - SINGL								15
4/0 - AAC - SINGL								16
1113 - AAC - SING								17
4/0 - AAC - UNKNO								18
4/0 - AAC - SINGL								19
4/0 - AAC - SINGL								20
4/0 - AAC - SINGL								21
477 - ACSS - SING								22
4/0 - ACAR - SING								23
477 - ACSS - SING								24
4/0 - AAC - SINGL								25
4/0 - AAC - SINGL								26
266.8 - AAC - SIN								27
4/0 - AAC - SINGL								28
4/0 - AAC - SINGL								29
715.5 - ALUM - SI								30
4/0 - ACSR - SING								31
4/0 - ACSR - SING								32
477 - ACSS - SING								33
397.5 - AAC - SIN								34
1/0 - ACSR - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
715.5 - AAC - SIN								1
397.5 - AAC - SIN								2
3/0 - CU - SINGLE								3
336.4 - AAC - SIN								4
715.5 - AAC - SIN								5
397.5 - AAC - SIN								6
397.5 - AAC - SIN								7
397.5 - AAC - SIN								8
477 - ACSS - SING								9
2 - ACSR - SINGLE								10
4/0 - AAC - SINGL								11
1/0 - ACSR - SING								12
715.5 - AAC - SIN								13
336.4 - AAC - SIN								14
715.5 - AAC - SIN								15
4/0 - AAC - SINGL								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
4/0 - CU - SINGLE								20
397.5 - AAC - SIN								21
4 - CU - SINGLE								22
397.5 - AAC - SIN								23
4/0 - AAC - SINGL								24
2 - ACSR - SINGLE								25
715.5 - AAC - SIN								26
397.5 - ALUM - SI								27
715.5 - AAC - SIN								28
477 - ACSS - SING								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
1/0 - ACSR - SING								32
4/0 - AAC - SINGL								33
4 - CU - SINGLE								34
397.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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715.5 - AAC - SIN								1
477 - ACSS - SING								2
397.5 - AAC - SIN								3
1/0 - ACSR - SING								4
715.5 - AAC - SIN								5
4/0 - AAC - SINGL								6
266.8 - AAC - SIN								7
1/0 - ACSR - SING								8
1113 - AAC - SING								9
4/0 - AAC - SINGL								10
4/0 - AAC - SINGL								11
4/0 - AAC - SINGL								12
266.8 - AAC - SIN								13
715.5 - AAC - SIN								14
715.5 - AAC - SIN								15
397.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
4/0 - CU - SINGLE								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
4 - CU - SINGLE 2								23
397.5 - AAC - SIN								24
4/0 - CU - SINGLE								25
397.5 - AAC - SIN								26
336.4 - AAC - SIN								27
397.5 - AAC - SIN								28
715.5 - AAC - SIN								29
1/0 - ACSR - SING								30
715.5 - AAC - SIN								31
397.5 - AAC - SIN								32
397.5 - AAC - SIN								33
2/0 - CU - SINGLE								34
1431 - AAC - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
4/0 - AAC - SINGL								1
397.5 - AAC - SIN								2
715.5 - AAC - SIN								3
715.5 - AAC - SIN								4
2/0 - CU - SINGLE								5
397.5 - AAC - SIN								6
1/0 - CU - SINGLE								7
1 - UNKNOWN -								8
715.5 - AAC - SIN								9
2/0 - CU - SINGLE								10
397.5 - AAC - SIN								11
397.5 - AAC - SIN								12
1/0 - CU - SINGLE								13
336.4 - AAC - SIN								14
2 - ACSR - SINGLE								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
4/0 - AAC - SINGL								18
2/0 - ACSR - SING								19
4/0 - AAC - SINGL								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
715.5 - AAC - SIN								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
336.4 - AAC - SIN								27
715.5 - AAC - SIN								28
397.5 - AAC - SIN								29
4 - CU - SINGLE								30
471 - AAC - SINGL								31
4/0 - ACSR - SING								32
715.5 - AAC - SIN								33
477 - ACSS - SING								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
1/0 - ACSR - SING								1
4/0 - AAC - SINGL								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
3/0 - CU - BUNDLE								5
1/0 - ACSR - SING								6
715.5 - AAC - SIN								7
2/0 - CU - SINGLE								8
4/0 - AAC - SINGL								9
4/0 - AAC - SINGL								10
715.5 - AAC - SIN								11
2/0 - CU - SINGLE								12
715.5 - AAC - SIN								13
4/0 - AAC - SINGL								14
4/0 - AAC - SINGL								15
4/0 - AAC - SINGL								16
4/0 - AAC - SINGL								17
1113 - AAC - SING								18
715.5 - AAC - SIN								19
4/0 - CU - SINGLE								20
4 - CU - SINGLE								21
4/0 - AAC - SINGL								22
1 - CU - SINGLE 1								23
4/0 - AAC - SINGL								24
4/0 - AAC - SINGL								25
								26
715.5 - AAC - SIN								27
336.4 - AAC - SIN								28
4/0 - AAC - SINGL								29
715.5 - AAC - SIN								30
4/0 - AAC - SINGL								31
715.5 - AAC - SIN								32
1113 - AAC - SING								33
336.4 - AAC - SIN								34
397.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
397.5 - ACSR - SI								1
4/0 - AAC - SINGL								2
4/0 - ACAR - SING								3
715.5 - AAC - SIN								4
4/0 - CU - SINGLE								5
3/0 - CU - SINGLE								6
715.5 - AAC - SIN								7
								8
715.5 - AAC - SIN								9
715.5 - AAC - SIN								10
4/0 - ACSR - SING								11
1/0 - CU - SINGLE								12
1/0 - ACSR - SING								13
4/0 - AAC - SINGL								14
4/0 - AAC - SINGL								15
715.5 - AAC - SIN								16
715.5 - AAC - SIN								17
715.5 - AAC - SIN								18
715.5 - AAC - SIN								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
4/0 - AAC - SINGL								22
397.5 - AAC - SIN								23
4/0 - ACSR - SING								24
4/0 - AAC - SINGL								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
715.5 - AAC - SIN								28
1/0 - ACSR - SING								29
1/0 - ACSR - SING								30
3/0 - AAC - SINGL								31
1/0 - ACSR - SING								32
715.5 - AAC - SIN								33
397.5 - AAC - SIN								34
397.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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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)	
3/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
4/0 - CU - SINGLE								3
4/0 - AAC - SINGL								4
715.5 - AAC - SIN								5
715.5 - AAC - SIN								6
715.5 - AAC - SIN								7
4/0 - AAC - SINGL								8
4/0 - AAC - SINGL								9
1 - UNKNOWN -								10
3/0 - AAC - SINGL								11
4/0 - AAC - SINGL								12
1113 - AAC - SING								13
715.5 - AAC - SIN								14
1/0 - ACSR - SING								15
397.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
715.5 - AAC - SIN								18
4/0 - AAC - SINGL								19
715.5 - AAC - SIN								20
4/0 - AAC - SINGL								21
4/0 - ACSR - SING								22
4/0 - AAC - SINGL								23
3/0 - AAC - SINGL								24
266.8 - AAC - SIN								25
715.5 - AAC - SIN								26
397.5 - AAC - SIN								27
715.5 - AAC - SIN								28
1/0 - AAC - SINGL								29
715.5 - AAC - SIN								30
715.5 - AAC - SIN								31
266.8 - AAC - SIN								32
715.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
715.5 - AAC - SIN								1
1 - CU - SINGLE 7								2
715.5 - AAC - SIN								3
397.5 - AAC - SIN								4
4/0 - AAC - SINGL								5
715.5 - AAC - SIN								6
397.5 - AAC - SIN								7
1/0 - ACSR - SING								8
4/0 - AAC - SINGL								9
397.5 - AAC - SIN								10
4/0 - ACSR - SING								11
715.5 - AAC - SIN								12
715.5 - AAC - SIN								13
715.5 - AAC - SIN								14
4/0 - AAC - SINGL								15
715.5 - AAC - SIN								16
4/0 - AAC - SINGL								17
1113 - AAC - SING								18
477 - ACSS - SING								19
715.5 - AAC - SIN								20
715.5 - AAC - SIN								21
715.5 - AAC - SIN								22
715.5 - AAC - SIN								23
4/0 - CU - SINGLE								24
4/0 - AAC - SINGL								25
715.5 - AAC - SIN								26
715.5 - AAC - SIN								27
1113 - AAC - SING								28
715.5 - AAC - SIN								29
397.5 - AAC - SIN								30
477 - ACSS - SING								31
4/0 - AAC - SINGL								32
1/0 - AAC - SINGL								33
4/0 - CU - SINGLE								34
1/0 - ACSR - SING								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
477 - ACSS - SING								1
477 - ACSS - SING								2
4/0 - AAC - SINGL								3
266.8 - AAC - SIN								4
266.8 - AAC - SIN								5
4/0 - AAC - SINGL								6
1113 - AAC - SING								7
715.5 - AAC - SIN								8
4/0 - AAC - SINGL								9
2 - ACSR - SINGLE								10
1113 - AAC - SING								11
715.5 - AAC - SIN								12
397.5 - AAC - SIN								13
2/0 - CU - SINGLE								14
1113 - AAC - SING								15
4/0 - AAC - SINGL								16
4/0 - AAC - SINGL								17
4/0 - AAC - SINGL								18
715.5 - AAC - SIN								19
397.5 - AAC - SIN								20
1/0 - ACSR - SING								21
2 - ACSR - SINGLE								22
1113 - AAC - SING								23
4/0 - AAC - SINGL								24
4/0 - AAC - SINGL								25
2 - UNKNOWN -								26
1113 - AAC - SING								27
715.5 - AAC - SIN								28
3/0 - AAC - SINGL								29
477 - ACSS - SING								30
1/0 - CU - SINGLE								31
715.5 - AAC - SIN								32
397.5 - AAC - SIN								33
715.5 - AAC - SIN								34
715.5 - AAC - SIN								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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)			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)	
4/0 - AAC - SINGL								1
715.5 - AAC - SIN								2
715.5 - AAC - SIN								3
4/0 - AAC - SINGL								4
4/0 - AAC - SINGL								5
266.8 - AAC - SIN								6
1113 - AAC - SING								7
1113 - AAC - SING								8
715.5 - AAC - SIN								9
4/0 - AAC - SINGL								10
4/0 - CU - SINGLE								11
4/0 - CU - SINGLE								12
1113 - AAC - SING								13
1/0 - CU - SINGLE								14
1113 - AAC - SING								15
4/0 - AAC - SINGL								16
4/0 - AAC - SINGL								17
2 - ACSR - SINGLE								18
4/0 - AAC - SINGL								19
4/0 - AAC - SINGL								20
397.5 - ALUM - SI								21
715.5 - AAC - SIN								22
397.5 - AAC - SIN								23
397.5 - AAC - SIN								24
715.5 - AAC - SIN								25
4/0 - AAC - SINGL								26
4/0 - AAC - SINGL								27
1/0 - ACSR - SING								28
2 - ACSR - SINGLE								29
397.5 - AAC - SIN								30
1113 - AAC - SING								31
1113 - AAC - SING								32
4/0 - AAC - SINGL								33
715.5 - AAC - SIN								34
4/0 - AAC - SINGL								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	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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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1/0 - ACSR - SING								1
397.5 - ACSR - SI								2
715.5 - AAC - SIN								3
1/0 - ACSR - SING								4
1113 - AAC - SING								5
336.4 - AAC - SIN								6
1/0 - ACSR - SING								7
1 - CU - SINGLE								8
397.5 - AAC - SIN								9
715.5 - AAC - SIN								10
4/0 - AAC - SINGL								11
2 - CU - SINGLE								12
397.5 - AAC - SIN								13
1113 - AAC - SING								14
1113 - AAC - SING								15
1113 - AAC - SING								16
4/0 - AAC - SINGL								17
1113 - AAC - SING								18
1113 - AAC - SING								19
1113 - AAC - SING								20
477 - ACSS - SING								21
1 - CU - SINGLE 3								22
715.5 - AAC - SIN								23
1 - UNKNOWN -								24
								25
								26
								27
								28
								29
2000 KCMIL - CU								30
3500 KCMIL - CU								31
3500 KCMIL - CU								32
2500 KCMIL - CU								33
2000 KCMIL - CU								34
3000 KCMIL - CU								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
2500 KCMIL - CU								1
3500 KCMIL - CU								2
2000 KCMIL - CU								3
2500 KCMIL - CU								4
2500 KCMIL - CU								5
2000 KCMIL - CU								6
UNKNOWN -								7
1250 KCMIL - CU								8
1250 KCMIL								9
1250 KCMIL - CU								10
3000 KCMIL -								11
1000 KCMIL - CU								12
1250 KCMIL								13
1250 KCMIL - CU								14
1250 KCMIL - CU								15
1000 KCMIL - CU								16
1000 KCMIL - CU								17
1250 KCMIL - CU								18
3000 KCMIL								19
1250 KCMIL - CU								20
3000 KCMIL								21
3000 KCMIL -								22
UNKNOWN -								23
2000 KCMIL - CU								24
3000 KCMIL - CU								25
500 KCMIL -								26
3000 KCMIL -								27
3000 KCMIL -								28
3000 KCMIL -								29
3000 KCMIL -								30
3000 KCMIL -								31
3000 KCMIL -								32
2000 KCMIL -								33
UNKNOWN -								34
UNKNOWN -								35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
UNKNOWN -								1
3500 KCMIL								2
2500 KCMIL - CU								3
2500 KCMIL - CU								4
1250 KCMIL -								5
3500 KCMIL -								6
3500 KCMIL -								7
1750 KCMIL -								8
2500 KCMIL - CU								9
2500 KCMIL - CU								10
1750 KCMIL -								11
UNKNOWN - CU								12
UNKNOWN - CU								13
3000 KCMIL - CU								14
3000 KCMIL - CU								15
1250 KCMIL -								16
								17
								18
								19
								20
								21
								22
								23
	28,281,080	550,658,158	578,939,238	9,367,967	20,711,609		30,079,576	24
	75,388,295	2,150,499,783	2,225,888,078	37,633,060	83,202,815		120,835,875	25
	89,622,893	1,355,050,205	1,444,673,098	42,835,878	94,705,710		137,541,588	26
	14,353,150	294,815,205	309,168,355	10,902,063	24,103,338		35,005,401	27
	33,536,197	764,229,266	797,765,463	27,391,213	60,559,148		87,950,361	28
								29
	2,790,742	238,509,403	241,300,145	200,554	1,114,515		1,315,069	30
	118,250	616,896,518	617,014,768	197,620	1,098,213		1,295,833	31
								32
		25,260,269	25,260,269	12,095	62,734		74,829	33
								34
		132,322,086	132,322,086					35
	244,090,607	6,128,240,893	6,372,331,500	128,540,450	285,558,082		414,098,532	36

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 1 Column: e

SSP - Single Steel Poles; SWP - Single Wood Poles; T - Steel Towers; Other - Multi_Pole Structures or Other Materials

Schedule Page: 422 Line No.: 1 Column: f

Timing differences may exist between ETGIS operational data on page 422-423 and the financial records on page 424-425.

Schedule Page: 422 Line No.: 15 Column: a

Bundle

Schedule Page: 422 Line No.: 22 Column: a

Idle

Schedule Page: 422 Line No.: 22 Column: i

Information not available as of the date of this report

Schedule Page: 422 Line No.: 23 Column: a

Bundle

Schedule Page: 422 Line No.: 30 Column: a

Idle

Schedule Page: 422 Line No.: 32 Column: a

Idle

Schedule Page: 422 Line No.: 32 Column: e

Information not available as of the date of this report

Schedule Page: 422 Line No.: 33 Column: a

Idle

Schedule Page: 422.1 Line No.: 1 Column: a

Idle

Schedule Page: 422.1 Line No.: 3 Column: a

Idle

Schedule Page: 422.1 Line No.: 7 Column: a

Bundle

Schedule Page: 422.1 Line No.: 13 Column: i

Information not available as of the date of this report

Schedule Page: 422.1 Line No.: 23 Column: a

Idle

Schedule Page: 422.1 Line No.: 24 Column: e

Information not available as of the date of this report

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

Information not available as of the date of this report

Schedule Page: 422.2 Line No.: 26 Column: a

Alum

Schedule Page: 422.2 Line No.: 27 Column: a

Bundle

Schedule Page: 422.2 Line No.: 29 Column: e

Information not available as of the date of this report

Schedule Page: 422.3 Line No.: 5 Column: a

Alum

Schedule Page: 422.3 Line No.: 28 Column: a

Idle

Schedule Page: 422.3 Line No.: 30 Column: a

Idle

Schedule Page: 422.3 Line No.: 30 Column: e

Information not available as of the date of this report

Schedule Page: 422.4 Line No.: 29 Column: a

Idle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.4 Line No.: 31 Column: a

Bundle

Schedule Page: 422.4 Line No.: 33 Column: i

Information not available as of the date of this report

Schedule Page: 422.4 Line No.: 35 Column: a

Idle

Schedule Page: 422.5 Line No.: 26 Column: i

Information not available as of the date of this report

Schedule Page: 422.5 Line No.: 33 Column: e

Information not available as of the date of this report

Schedule Page: 422.6 Line No.: 4 Column: a

Alum

Schedule Page: 422.6 Line No.: 5 Column: e

Information not available as of the date of this report

Schedule Page: 422.6 Line No.: 6 Column: a

Bundle

Schedule Page: 422.6 Line No.: 7 Column: a

Bundle

Schedule Page: 422.6 Line No.: 15 Column: a

Idle

Schedule Page: 422.6 Line No.: 17 Column: e

Information not available as of the date of this report

Schedule Page: 422.6 Line No.: 20 Column: a

Alum

Schedule Page: 422.6 Line No.: 21 Column: a

Alum

Schedule Page: 422.6 Line No.: 24 Column: i

Information not available as of the date of this report

Schedule Page: 422.6 Line No.: 28 Column: a

Bundle

Schedule Page: 422.7 Line No.: 3 Column: e

Information not available as of the date of this report

Schedule Page: 422.7 Line No.: 17 Column: e

Information not available as of the date of this report

Schedule Page: 422.7 Line No.: 21 Column: e

Information not available as of the date of this report

Schedule Page: 422.7 Line No.: 27 Column: a

Bundle

Schedule Page: 422.7 Line No.: 30 Column: a

Bundle

Schedule Page: 422.7 Line No.: 34 Column: e

Information not available as of the date of this report

Schedule Page: 422.7 Line No.: 35 Column: a

Bundle

Schedule Page: 422.8 Line No.: 33 Column: e

Information not available as of the date of this report

Schedule Page: 422.9 Line No.: 9 Column: a

Idle

Schedule Page: 422.9 Line No.: 9 Column: e

Information not available as of the date of this report

Schedule Page: 422.9 Line No.: 10 Column: a

Bundle

Schedule Page: 422.9 Line No.: 11 Column: a

Bundle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.9 Line No.: 14 Column: a

Idle

Schedule Page: 422.9 Line No.: 23 Column: e

Information not available as of the date of this report

Schedule Page: 422.9 Line No.: 26 Column: e

Information not available as of the date of this report

Schedule Page: 422.9 Line No.: 28 Column: a

Bundle

Schedule Page: 422.10 Line No.: 18 Column: a

Bundle

Schedule Page: 422.10 Line No.: 19 Column: a

Idle

Schedule Page: 422.11 Line No.: 8 Column: e

Information not available as of the date of this report

Schedule Page: 422.11 Line No.: 18 Column: a

Idle

Schedule Page: 422.11 Line No.: 18 Column: e

Information not available as of the date of this report

Schedule Page: 422.11 Line No.: 19 Column: a

Bundle

Schedule Page: 422.11 Line No.: 20 Column: a

Bundle

Schedule Page: 422.11 Line No.: 21 Column: a

Bundle

Schedule Page: 422.11 Line No.: 25 Column: a

Bundle

Schedule Page: 422.11 Line No.: 26 Column: a

Bundle

Schedule Page: 422.11 Line No.: 31 Column: e

Information not available as of the date of this report

Schedule Page: 422.12 Line No.: 1 Column: e

Information not available as of the date of this report

Schedule Page: 422.12 Line No.: 6 Column: e

Information not available as of the date of this report

Schedule Page: 422.12 Line No.: 26 Column: a

Alum

Schedule Page: 422.12 Line No.: 27 Column: a

Alum

Schedule Page: 422.12 Line No.: 30 Column: e

Information not available as of the date of this report

Schedule Page: 422.13 Line No.: 2 Column: a

Idle

Schedule Page: 422.13 Line No.: 3 Column: a

Idle

Schedule Page: 422.13 Line No.: 3 Column: e

Information not available as of the date of this report

Schedule Page: 422.13 Line No.: 10 Column: a

Bundle

Schedule Page: 422.13 Line No.: 16 Column: e

Information not available as of the date of this report

Schedule Page: 422.13 Line No.: 28 Column: e

Information not available as of the date of this report

Schedule Page: 422.13 Line No.: 29 Column: a

Idle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.13 Line No.: 30 Column: a
Idle

Schedule Page: 422.14 Line No.: 15 Column: i
Information not available as of the date of this report

Schedule Page: 422.14 Line No.: 23 Column: a
Bundle

Schedule Page: 422.14 Line No.: 29 Column: a
Idle

Schedule Page: 422.14 Line No.: 30 Column: a
Bundle

Schedule Page: 422.15 Line No.: 29 Column: e
Information not available as of the date of this report

Schedule Page: 422.16 Line No.: 7 Column: a
Idle

Schedule Page: 422.16 Line No.: 11 Column: a
Bundle

Schedule Page: 422.16 Line No.: 12 Column: e
Information not available as of the date of this report

Schedule Page: 422.16 Line No.: 14 Column: a
Bundle

Schedule Page: 422.16 Line No.: 17 Column: a
Bundle

Schedule Page: 422.16 Line No.: 19 Column: a
Bundle

Schedule Page: 422.16 Line No.: 23 Column: a
Bundle

Schedule Page: 422.17 Line No.: 6 Column: e
Information not available as of the date of this report

Schedule Page: 422.17 Line No.: 18 Column: a
Bundle

Schedule Page: 422.17 Line No.: 18 Column: e
Information not available as of the date of this report

Schedule Page: 422.17 Line No.: 28 Column: a
Bundle

Schedule Page: 422.17 Line No.: 30 Column: a
Bundle

Schedule Page: 422.17 Line No.: 32 Column: a
Bundle

Schedule Page: 422.17 Line No.: 33 Column: a
Bundle, Idle

Schedule Page: 422.18 Line No.: 1 Column: e
Information not available as of the date of this report

Schedule Page: 422.18 Line No.: 6 Column: a
Bundle

Schedule Page: 422.18 Line No.: 7 Column: a
Bundle

Schedule Page: 422.18 Line No.: 8 Column: a
Bundle

Schedule Page: 422.18 Line No.: 11 Column: a
Bundle

Schedule Page: 422.18 Line No.: 12 Column: a
Bundle

Schedule Page: 422.18 Line No.: 15 Column: a
Bundle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.18 Line No.: 16 Column: a
Bundle

Schedule Page: 422.18 Line No.: 17 Column: a
Bundle

Schedule Page: 422.18 Line No.: 20 Column: a
Bundle

Schedule Page: 422.18 Line No.: 21 Column: a
Bundle

Schedule Page: 422.18 Line No.: 22 Column: a
Bundle

Schedule Page: 422.18 Line No.: 35 Column: a
Bundle

Schedule Page: 422.19 Line No.: 1 Column: a
Bundle

Schedule Page: 422.19 Line No.: 3 Column: a
Bundle

Schedule Page: 422.19 Line No.: 4 Column: a
Bundle

Schedule Page: 422.19 Line No.: 4 Column: e
Information not available as of the date of this report

Schedule Page: 422.19 Line No.: 5 Column: a
Bundle

Schedule Page: 422.19 Line No.: 6 Column: a
Bundle

Schedule Page: 422.19 Line No.: 7 Column: a
Bundle

Schedule Page: 422.19 Line No.: 9 Column: a
Bundle

Schedule Page: 422.19 Line No.: 12 Column: a
Bundle

Schedule Page: 422.19 Line No.: 14 Column: a
Bundle

Schedule Page: 422.19 Line No.: 20 Column: a
Bundle

Schedule Page: 422.19 Line No.: 21 Column: e
Information not available as of the date of this report

Schedule Page: 422.19 Line No.: 23 Column: e
Information not available as of the date of this report

Schedule Page: 422.19 Line No.: 24 Column: e
Information not available as of the date of this report

Schedule Page: 422.19 Line No.: 25 Column: a
Bundle

Schedule Page: 422.19 Line No.: 28 Column: a
Bundle

Schedule Page: 422.19 Line No.: 31 Column: a
Bundle

Schedule Page: 422.19 Line No.: 34 Column: e
Information not available as of the date of this report

Schedule Page: 422.20 Line No.: 7 Column: a
Bundle

Schedule Page: 422.20 Line No.: 8 Column: a
Bundle

Schedule Page: 422.20 Line No.: 9 Column: a
Bundle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.20 Line No.: 33 Column: a

Bundle

Schedule Page: 422.21 Line No.: 1 Column: a

Bundle

Schedule Page: 422.21 Line No.: 1 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 2 Column: a

Bundle

Schedule Page: 422.21 Line No.: 3 Column: a

Bundle

Schedule Page: 422.21 Line No.: 4 Column: a

Bundle

Schedule Page: 422.21 Line No.: 7 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 8 Column: a

Bundle

Schedule Page: 422.21 Line No.: 17 Column: a

Bundle

Schedule Page: 422.21 Line No.: 17 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 18 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 20 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 22 Column: a

Bundle

Schedule Page: 422.21 Line No.: 23 Column: a

Bundle

Schedule Page: 422.21 Line No.: 25 Column: e

Information not available as of the date of this report

Schedule Page: 422.21 Line No.: 26 Column: a

Bundle

Schedule Page: 422.21 Line No.: 27 Column: a

Bundle

Schedule Page: 422.21 Line No.: 31 Column: a

Bundle

Schedule Page: 422.22 Line No.: 4 Column: e

Information not available as of the date of this report

Schedule Page: 422.22 Line No.: 5 Column: a

Bundle

Schedule Page: 422.22 Line No.: 17 Column: a

Bundle

Schedule Page: 422.22 Line No.: 18 Column: a

Bundle

Schedule Page: 422.22 Line No.: 19 Column: a

Bundle

Schedule Page: 422.22 Line No.: 20 Column: a

Bundle

Schedule Page: 422.22 Line No.: 21 Column: a

Bundle

Schedule Page: 422.22 Line No.: 22 Column: a

Bundle

Schedule Page: 422.22 Line No.: 23 Column: a

Bundle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.22 Line No.: 24 Column: a

Bundle

Schedule Page: 422.22 Line No.: 25 Column: a

Bundle

Schedule Page: 422.22 Line No.: 26 Column: a

Bundle

Schedule Page: 422.22 Line No.: 27 Column: a

Bundle

Schedule Page: 422.22 Line No.: 28 Column: a

Bundle

Schedule Page: 422.22 Line No.: 29 Column: a

Bundle

Schedule Page: 422.22 Line No.: 30 Column: a

Bundle

Schedule Page: 422.22 Line No.: 31 Column: a

Bundle

Schedule Page: 422.22 Line No.: 32 Column: a

Bundle

Schedule Page: 422.22 Line No.: 33 Column: a

Bundle

Schedule Page: 422.22 Line No.: 34 Column: a

Bundle

Schedule Page: 422.22 Line No.: 35 Column: a

Bundle

Schedule Page: 422.23 Line No.: 1 Column: a

Bundle

Schedule Page: 422.23 Line No.: 2 Column: a

Bundle

Schedule Page: 422.23 Line No.: 3 Column: a

Bundle

Schedule Page: 422.23 Line No.: 5 Column: a

Bundle

Schedule Page: 422.23 Line No.: 6 Column: a

Bundle

Schedule Page: 422.23 Line No.: 20 Column: i

Information not available as of the date of this report

Schedule Page: 422.23 Line No.: 25 Column: a

Bundle

Schedule Page: 422.23 Line No.: 29 Column: i

Information not available as of the date of this report

Schedule Page: 422.24 Line No.: 4 Column: a

Idle

Schedule Page: 422.24 Line No.: 7 Column: a

Idle

Schedule Page: 422.24 Line No.: 13 Column: a

Bundle

Schedule Page: 422.24 Line No.: 21 Column: a

Bundle

Schedule Page: 422.24 Line No.: 34 Column: a

Idle

Schedule Page: 422.24 Line No.: 34 Column: e

Information not available as of the date of this report

Schedule Page: 422.24 Line No.: 35 Column: a

Idle

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.25 Line No.: 2 Column: a

Idle

Schedule Page: 422.25 Line No.: 4 Column: a

Bundle

Schedule Page: 422.25 Line No.: 5 Column: a

Bundle

Schedule Page: 422.25 Line No.: 24 Column: a

Bundle

Schedule Page: 422.26 Line No.: 32 Column: a

Idle

Schedule Page: 422.27 Line No.: 3 Column: a

Bundle

Schedule Page: 422.28 Line No.: 14 Column: a

Alum

Schedule Page: 422.28 Line No.: 31 Column: i

Information not available as of the date of this report

Schedule Page: 422.29 Line No.: 19 Column: a

Idle

Schedule Page: 422.29 Line No.: 24 Column: a

Alum

Schedule Page: 422.29 Line No.: 30 Column: a

Alum

Schedule Page: 422.30 Line No.: 13 Column: a

Idle

Schedule Page: 422.30 Line No.: 17 Column: a

Idle

Schedule Page: 422.30 Line No.: 19 Column: a

Idle

Schedule Page: 422.30 Line No.: 26 Column: a

Alum

Schedule Page: 422.30 Line No.: 27 Column: a

Alum

Schedule Page: 422.31 Line No.: 30 Column: a

Idle

Schedule Page: 422.31 Line No.: 33 Column: a

Idle

Schedule Page: 422.32 Line No.: 8 Column: a

Idle

Schedule Page: 422.32 Line No.: 31 Column: a

Idle

Schedule Page: 422.33 Line No.: 5 Column: a

Bundle

Schedule Page: 422.33 Line No.: 15 Column: e

Information not available as of the date of this report

Schedule Page: 422.33 Line No.: 26 Column: i

Information not available as of the date of this report

Schedule Page: 422.34 Line No.: 8 Column: i

Information not available as of the date of this report

Schedule Page: 422.35 Line No.: 10 Column: a

Idle

Schedule Page: 422.35 Line No.: 27 Column: a

Idle

Schedule Page: 422.36 Line No.: 18 Column: e

Information not available as of the date of this report

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
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FOOTNOTE DATA

Schedule Page: 422.38	Line No.: 5	Column: a	Idle
Schedule Page: 422.38	Line No.: 6	Column: a	Idle
Schedule Page: 422.38	Line No.: 17	Column: a	Alum
Schedule Page: 422.38	Line No.: 21	Column: a	Alum
Schedule Page: 422.39	Line No.: 9	Column: a	Idle
Schedule Page: 422.39	Line No.: 24	Column: a	Idle
Schedule Page: 422.39	Line No.: 25	Column: a	Idle
Schedule Page: 422.39	Line No.: 25	Column: i	Information not available as of the date of this report
Schedule Page: 422.39	Line No.: 26	Column: a	Idle
Schedule Page: 422.39	Line No.: 26	Column: i	Information not available as of the date of this report
Schedule Page: 422.39	Line No.: 27	Column: a	Idle
Schedule Page: 422.39	Line No.: 27	Column: i	Information not available as of the date of this report
Schedule Page: 422.39	Line No.: 28	Column: a	Idle
Schedule Page: 422.39	Line No.: 28	Column: i	Information not available as of the date of this report
Schedule Page: 422.39	Line No.: 29	Column: a	Idle
Schedule Page: 422.39	Line No.: 29	Column: i	Information not available as of the date of this report
Schedule Page: 422.40	Line No.: 11	Column: a	Alum
Schedule Page: 422.40	Line No.: 22	Column: a	Idle
Schedule Page: 422.40	Line No.: 33	Column: a	Alum
Schedule Page: 422.41	Line No.: 5	Column: a	Alum
Schedule Page: 422.41	Line No.: 6	Column: a	Alum
Schedule Page: 422.41	Line No.: 7	Column: a	Alum
Schedule Page: 422.41	Line No.: 11	Column: a	Alum
Schedule Page: 422.41	Line No.: 16	Column: a	Alum

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 completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Removals						
2	Underground Construction						
3	Overhead Construction						
4							
5	Caribou-Palermo Removal						
6	Caribou	Palermo	20.00	Lattice Towers	7.80	1	1
7	Job Order # 31509392,						
8							
9	Reconductors						
10	Underground Construction						
11	Overhead Construction						
12							
13	GEYSERS 12-FULTON						
14	Geysers 12	Fulton	2.00	LDSP and TSP	9.50	1	1
15	Job Order # 74017860						
16							
17	PH 2-CARIBOU#2 GRAYS						
18	Carbou #2 Gray flat	Spanish Creek	4.30	WP and LDSP	7.50	1	1
19	Job Order # 74020221						
20							
21	TRINITY-COTTONWOOD						
22	Trinity	Cottonwood	7.10	2 & 3 wood pos	5.20	1	1
23	Job Order # 74024159						
24							
25	60-SOUTH OF PALERMO						
26	Palermo-Pease and	Pease substation	5.80	TSP and hybrs	2.90	1	1
27	Job Order # 74001396						
28							
29	(DA-B&M) ELECTRA-VALLEY						
30	Electric Substation	Valley Spring Substation	5.90	WP and LDSP	16.00	1	1
31	Job Order # 74001436						
32							
33	Q272 AMERICAN KINGS						
34	Henrietta Sub	American Kings Solar	0.20	TSP and LDSP	20.00	1	1
35	Job Order # 74001134						
36							
37	CLEAR LAKE KONOCTI						
38	Clear Lake/Konocti	State route 29	0.50	LDSP and TSP	3.00	1	1
39	Job Order # 74005352						
40							
41	SMARTVILLE-MARYSVILLE						
42	Smartville	Marysville	1.30	LDSP	3.00	1	1
43	Job Order # 74008565						
44	TOTAL		70.67		375.84	22	22

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 completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2	SMARTVILLE-MARYSVILLE						
3	Smartville	Marysville	0.30	WP	136.00	1	1
4	Job Order # 74011401						
5							
6	MANTECA #1 60 KV RELO-						
7	Manteca #1						
8	Job Order # 74014541	Manteca #1	0.17	WP and LDSP	35.30	1	1
9							
10	SCHINDLER-COALINGA#2						
11	Schindler						
12	Job Order # 74014542	Coalinga #2	0.09	WP	22.20	1	1
13							
14	TESLA-STOCKTON 115KV						
15	Tesla	Stockton Cogen Jct	1.00	WP and TSP	5.00	1	1
16	Job Order # 74016342						
17							
18	SURF TAP 115KV RELO						
19	Surf tap	Surf tap					
20	Job Order # 74017320		0.19	TSP	21.00	1	1
21							
22	TABLE						
23	Table mountain	Peachton	1.12	TSP	11.60	1	1
24	Job Order # 74019009						
25							
26	TABLE						
27	Table mountain	Peachton	1.24	WP	12.00	1	1
28	Job Order # 74019010						
29							
30	FULTON-CALISTOGA 60 KV						
31	Fulton	Calistoga	11.40	WP and LDSP	8.85	1	1
32	Job Order # 74024721						
33							
34	KASSON-LOUISE						
35	Kasson	Louise	1.50	WP, TSP, LDSP	8.00	1	1
36	Job Order # 74020723						
37							
38	ALMENDRA JCT-NICOLAUS						
39	Almendra Jct	Nicolaus	0.20	WP and LDSP	10.00	1	1
40	Job Order # 74028140						
41							
42	PLACER-DEL MAR 60 KV:						
43	Placer	Del Mar	0.35	WP	5.71	1	1
44	TOTAL		70.67		375.84	22	22

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 completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Job Order # 74030084						
2							
3	SYCAMORE CRK-NOTRE						
4	Sycamore Creek	Notre Dame	0.11	WP	18.00	1	1
5	Job Order # 74032063						
6							
7	MERCED						
8	Merced Falls	Exchequer	5.90	LSP	7.28	1	1
9	Job Order # 74001076						
10							
11							
12							
13							
14							
15							
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39							
40							
41							
42							
43							
44	TOTAL		70.67		375.84	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
									2
									3
									4
									5
3/0 - 397	CU -AAC	various	115		-7,885,764	-1,130,533		-9,016,297	6
									7
									8
									9
									10
									11
									12
									13
477	ACSS	various	230	2,938,488		10,275,436		13,213,924	14
									15
									16
									17
397	ACSR	various	60		6,173,989	2,581,323		8,755,312	18
									19
									20
									21
336.4	ACSR	various	115		3,105,189	3,693,340		6,798,529	22
									23
									24
									25
477	ACSS	various	115	9,329,075	6,265,851	8,963,996		24,558,922	26
									27
									28
									29
795	ACSR	various	60		13,445,421	-94,453		13,350,968	30
									31
									32
									33
715.5	AAC	various	70	7,710	615,340	866,071		1,489,121	34
									35
									36
									37
397	ACSR	various	60		835,175	821,431		1,656,606	38
									39
									40
									41
4/0	ACC	various	60	7,148	63,906	70,123		141,177	42
									43
									44
					12,952,223	71,804,969	40,607,541	125,364,733	44

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
397.5	KCM	various	115		106,886	169,147		276,033	4
									5
									6
									7
4/0-6/6/1	ACSR	various	70		3,552,814	2,828,560		6,381,374	8
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									39
									40
									41
									42
									43
					12,952,223	71,804,969	40,607,541	125,364,733	44

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	ARCO SUB, Lost Hills	Transmission	230.00	70.00	13.20
2	ATLANTIC SUB, Roseville	Transmission	230.00	60.00	13.20
3	ATLANTIC SUB, Roseville	Transmission	230.00	115.00	13.20
4	BAIR SUB, Redwood City	Transmission	115.00	60.00	13.20
5	BELLOTA SUB, Bellota	Transmission	230.00	115.00	13.20
6	BORDEN SUB, Madera	Transmission	230.00	70.00	13.20
7	BRIDGEVILLE SUB, Bridgeville	Transmission	115.00	60.00	13.20
8	BRIGHTON SUB, Sacramento	Transmission	230.00	115.00	13.20
9	BUTTE SUB, Chico	Transmission	115.00	60.00	13.20
10	CASCADE SUB, Pine Grove	Transmission	115.00	60.00	13.20
11	CHRISTIE SUB, Hercules	Transmission	115.00	60.00	13.20
12	COBURN SUB, King City	Transmission	230.00	60.00	13.20
13	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	60.00	13.20
14	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	115.00	13.20
15	COOLEY LANDING SUB, Palo Alto	Transmission	115.00	60.00	13.80
16	CORCORAN SUB, Corcoran	Transmission	115.00	70.00	13.20
17	CORTINA SUB, Williams	Transmission	115.00	60.00	13.20
18	CORTINA SUB, Williams	Transmission	230.00	115.00	13.20
19	COTTONWOOD SUB, Cottonwood	Transmission	230.00	60.00	13.20
20	COTTONWOOD SUB, Cottonwood	Transmission	230.00	115.00	13.20
21	DEL MONTE SUB, Monterey	Transmission	115.00	60.00	13.20
22	DIVIDE SUB, Orcutt	Transmission	115.00	70.00	13.20
23	EAGLE ROCK SUB, Geysers	Transmission	115.00	60.00	
24	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	60.00	
25	EASTSHORE SUB, Hayward	Transmission	230.00	115.00	
26	EVERGREEN SUB, San Jose	Transmission	115.00	60.00	13.20
27	FULTON SUB, Fulton	Transmission	115.00	60.00	13.20
28	FULTON SUB, Fulton	Transmission	230.00	115.00	13.20
29	GATES SUB, Huron	Transmission	230.00	70.00	13.20
30	GATES SUB, Huron	Transmission	230.00	115.00	13.20
31	GATES SUB, Huron	Transmission	500.00	230.00	13.20
32	GLENN SUB, Orland	Transmission	230.00	60.00	13.20
33	GOLD HILL SUB, Folsom	Transmission	115.00	60.00	13.20
34	GOLD HILL SUB, Folsom	Transmission	230.00	115.00	13.20
35	GREEN VALLEY SUB, Watsonville	Transmission	115.00	60.00	
36	HELM SUB, San Joaquin	Transmission	230.00	70.00	13.20
37	HENRIETTA SUB, Lamoore	Transmission	230.00	70.00	13.20
38	HENRIETTA SUB, Lamoore	Transmission	230.00	115.00	2.40
39	HERDLYN SUB, Tracy	Transmission	70.00	60.00	2.40
40	HERNDON SUB, Herndon	Transmission	230.00	115.00	13.20

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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	HOPLAND SUB, Hopland	Transmission	115.00	60.00	13.20
2	HUMBOLDT SUB SUB, Eureka	Transmission	115.00	60.00	13.20
3	IGNACIO SUB, Ignacio	Transmission	115.00	60.00	13.20
4	IGNACIO SUB, Ignacio	Transmission	230.00	115.00	13.20
5	JEFFERSON SUB, Redwood City	Transmission	230.00	60.00	13.20
6	KASSON SUB, Tracy	Transmission	115.00	60.00	13.20
7	KERN PP SUB, Bakersfield	Transmission	115.00	70.00	13.20
8	KERN PP SUB, Bakersfield	Transmission	230.00	115.00	13.20
9	KINGSBURG SUB, Kingsburg	Transmission	115.00	70.00	13.80
10	LAKEVILLE SUB, Petaluma	Transmission	230.00	60.00	13.20
11	LAKEVILLE SUB, Petaluma	Transmission	230.00	115.00	13.20
12	LAS POSITAS SUB, Livermore	Transmission	230.00	60.00	13.20
13	LOCKEFORD SUB, Lockeford	Transmission	230.00	60.00	13.20
14	LOS BANOS SUB, Los Banos	Transmission	230.00	70.00	13.20
15	LOS BANOS SUB, Los Banos	Transmission	500.00	230.00	13.80
16	LOS ESTEROS SUB,	Transmission	230.00	115.00	12.00
17	MANTECA SUB, Manteca	Transmission	115.00	60.00	13.20
18	MCCALL SUB, Selma	Transmission	230.00	115.00	13.20
19	MENDOCINO SUB, Redwood Valley	Transmission	115.00	60.00	13.20
20	MENDOTA SUB, Mendota	Transmission	115.00	70.00	12.00
21	MERCED SUB, Merced	Transmission	115.00	70.00	6.60
22	MESA SUB, Nipomo	Transmission	230.00	115.00	13.20
23	METCALF SUB, San Jose	Transmission	500.00	230.00	13.80
24	METCALF SUB, San Jose	Transmission	230.00	115.00	13.20
25	MIDWAY SUB, Buttonwillow	Transmission	230.00	115.00	13.20
26	MIDWAY SUB, Buttonwillow	Transmission	500.00	230.00	13.80
27	MILLBRAE SUB, Millbrae	Transmission	115.00	60.00	13.80
28	MONTA VISTA SUB, Cupertino	Transmission	115.00	60.00	13.20
29	MONTA VISTA SUB, Cupertino	Transmission	230.00	60.00	
30	MONTA VISTA SUB, Cupertino	Transmission	230.00	115.00	13.20
31	MORAGA SUB, Orinda	Transmission	230.00	115.00	13.20
32	MORRO BAY PP SWYD, Morro Bay	Transmission	230.00	115.00	13.20
33	MOSS LANDING PP SUB, Moss Landing	Transmission	230.00	115.00	13.20
34	MOSS LANDING PP SUB, Moss Landing	Transmission	500.00	230.00	13.80
35	NEW KEARNEY SUB, FRESNO	Transmission	230.00	70.00	13.20
36	NEWARK SUB, Fremont	Transmission	115.00	60.00	13.20
37	NEWARK SUB, Fremont	Transmission	230.00	115.00	13.20
38	ORO LOMA SUB, Dos Palos	Transmission	115.00	70.00	13.20
39	PALERMO SUB, Palermo	Transmission	230.00	60.00	
40	PALERMO SUB, Palermo	Transmission	230.00	115.00	13.20

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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	PANOCHESUB, Mendota	Transmission	230.00	115.00	13.20
2	PEASE SUB, Tierra Buena	Transmission	115.00	60.00	13.20
3	PITTSBURG PP SUB,	Transmission	230.00	115.00	13.20
4	PLACER SUB, Auburn	Transmission	115.00	60.00	
5	RAVENSWOOD SUB, Menlo Park	Transmission	230.00	115.00	13.20
6	REEDLEY SUB, Reedley	Transmission	115.00	70.00	13.20
7	RIO OSO SUB, Rio Oso	Transmission	230.00	115.00	13.20
8	ROUND MOUNTAIN SUB, Rd Mtn	Transmission	500.00	230.00	13.80
9	SALADO SUB, Patterson	Transmission	115.00	60.00	13.20
10	SALINAS SUB, Salinas	Transmission	115.00	60.00	13.20
11	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	230.00	115.00	13.20
12	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	60.00	
13	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	230.00	115.00	
14	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	70.00	13.20
15	SAN MATEO SUB, San Mateo	Transmission	115.00	60.00	
16	SAN MATEO SUB, San Mateo	Transmission	230.00	115.00	
17	SAN RAMON SUB, San Ramon	Transmission	230.00	60.00	13.20
18	SANGER SUB, Fresno	Transmission	115.00	70.00	6.60
19	SCHINDLER SUB, Five Points	Transmission	115.00	70.00	13.20
20	SEMITROPIC SUB, Wasco	Transmission	115.00	70.00	13.80
21	SOBRANTE SUB, Orinda	Transmission	230.00	115.00	
22	SOLEDAD SUB, Soledad	Transmission	115.00	60.00	
23	STAGG SUB, Stockton	Transmission	230.00	60.00	13.20
24	TABLE MOUNTAIN SUB, Oroville	Transmission	230.00	115.00	
25	TABLE MOUNTAIN SUB, Oroville	Transmission	500.00	230.00	13.80
26	TAFT SUB, Taft	Transmission	115.00	70.00	13.20
27	TEMPLETON SUB, TEMPLETON	Transmission	230.00	70.00	13.20
28	TESLA SUB, Tracy	Transmission	230.00	115.00	13.20
29	TESLA SUB, Tracy	Transmission	500.00	230.00	13.20
30	TRINITY SUB, Weaverville	Transmission	115.00	60.00	13.20
31	TULUCAY SUB, Napa	Transmission	230.00	60.00	13.20
32	VACA DIXON SUB, Vacaville	Transmission	115.00	60.00	13.20
33	VACA DIXON SUB, Vacaville	Transmission	230.00	115.00	13.20
34	VACA DIXON SUB, Vacaville	Transmission	500.00	230.00	13.80
35	VALLEY SPRINGS SUB, Valley Springs	Transmission	230.00	60.00	13.20
36	WEBER SUB, Stockton	Transmission	230.00	60.00	13.20
37	WHEELER RIDGE SUB, Bakersfield	Transmission	115.00	70.00	13.20
38	WHEELER RIDGE SUB, Bakersfield	Transmission	230.00	70.00	13.20
39	WILSON SUB, Merced	Transmission	230.00	115.00	13.20
40	7th STANDARD SUB, Bakersfield	Distribution	115.00	21.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	AIRWAYS SUB, Fresno, Ca.	Distribution	115.00	12.00	7.20
2	ALHAMBRA SUB, Martinez	Distribution	115.00	12.00	7.20
3	ALLEGHANY SUB, Alleghany	Distribution	60.00	12.00	7.20
4	ALMADEN SUB, San Jose	Distribution	60.00	12.00	7.20
5	ALPAUGH SUB, Tulare	Distribution	115.00	12.00	
6	ALTO SUB, Mill Valley	Distribution	60.00	12.00	2.40
7	AMES DISTRIBUTION SUB, Mountain View	Distribution	115.00	12.00	7.20
8	ANDERSON SUB, Anderson	Distribution	60.00	12.00	2.40
9	ANGIOLA SUB, Kings	Distribution	70.00	12.00	7.20
10	ANITA SUB, Chico	Distribution	60.00	12.00	2.40
11	ANTELOPE SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
12	ANTLER SUB, Lakehead	Distribution	60.00	12.00	2.40
13	APPLE HILL SUB, Camino	Distribution	115.00	12.00	7.20
14	APPLE HILL SUB, Camino	Distribution	115.00	21.00	7.20
15	ARBUCKLE SUB, ARBUCKLE	Distribution	60.00	12.00	7.20
16	ARCATA SUB, Arcata	Distribution	60.00	12.00	2.40
17	ARVIN SUB, Arvin	Distribution	70.00	12.00	2.40
18	ASHLAN AVENUE SUB, Fresno	Distribution	230.00	12.00	7.20
19	ATASCADERO SUB, Atascadero	Distribution	115.00	12.00	7.20
20	ATWATER SUB, Atwater	Distribution	115.00	12.00	7.20
21	AUBERRY SUB, Auberry	Distribution	70.00	12.00	7.20
22	AVENA SUB, Escalon	Distribution	115.00	12.00	
23	AVENAL SUB, Avenal	Distribution	70.00	12.00	
24	BAHIA SUB, Benicia	Distribution	230.00	12.00	7.20
25	BAIR SUB, Redwood City	Transmission	115.00	12.00	7.20
26	BAKERSFIELD SUB, Bakersfield	Distribution	230.00	21.00	7.20
27	BANGOR SUB, Bangor	Distribution	60.00	12.00	7.20
28	BARTON SUB, Fresno	Distribution	115.00	12.00	7.20
29	BASALT SUB, Napa	Distribution	60.00	12.00	2.40
30	BAY MEADOWS SUB, San Mateo	Distribution	115.00	21.00	7.20
31	BAY MEADOWS SUB, San Mateo	Distribution	115.00	12.00	7.20
32	BAYWOOD SUB, Morro Bay	Distribution	70.00	12.00	2.40
33	BEAR VALLEY SUB, Bear Valley	Distribution	70.00	21.00	7.20
34	BELL SUB, Auburn	Distribution	115.00	12.00	7.20
35	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	12.00	2.40
36	BELLE HAVEN SUB, Menlo Park	Distribution	60.00	4.00	2.40
37	BELLEVUE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
38	BELMONT SUB, Belmont	Distribution	115.00	12.00	7.20
39	BERRENDA A SUB,	Distribution	70.00	4.00	2.40
40	BIG BASIN SUB, Santa Cruz	Distribution	60.00	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	BIG MEADOWS SUB, Greenville	Distribution	60.00	44.00	2.40
2	BIOLA SUB, Biola	Distribution	70.00	12.00	2.40
3	BLACKWELL SUB, Blackwell Corner	Distribution	70.00	12.00	2.40
4	BLUE LAKE SUB, Blue Lake	Distribution	60.00	12.00	2.40
5	BOGUE SUB, Yuba City	Distribution	115.00	12.00	7.20
6	BOLINAS SUB, Boninas	Distribution	60.00	12.00	7.20
7	BONITA SUB, Madera	Distribution	70.00	12.00	7.20
8	BORDEN SUB, Madera	Transmission	230.00	12.00	7.20
9	BOWLES SUB, Bowles	Distribution	70.00	12.00	7.20
10	BRENTWOOD SUB, Brentwood	Distribution	230.00	21.00	7.20
11	BRITTON SUB, Sunnyvale	Distribution	115.00	12.00	
12	BRUNSWICK SUB, Grass Valley	Distribution	115.00	12.00	7.20
13	BUELLTON SUB, Buellton /93427	Distribution	115.00	12.00	7.20
14	BUENA VISTA SUB, Salinas	Distribution	60.00	12.00	7.20
15	BULLARD SUB, Fresno	Distribution	115.00	12.00	7.20
16	BULLARD SUB, Fresno	Distribution	115.00	21.00	7.20
17	BURLINGAME SUB, Burlingame	Distribution	115.00	21.00	7.20
18	BUTTE SUB, Chico	Transmission	115.00	12.00	7.20
19	CABRILLO SUB, LOMPOC	Distribution	115.00	12.00	7.20
20	CADET SUB, Maricopa	Distribution	70.00	12.00	
21	CAL WATER SUB,	Distribution	115.00	12.00	7.20
22	CALAVERAS CEMENT SUB, San Andreas	Distribution	60.00	12.00	7.20
23	CALFLAX SUB, Huron	Distribution	70.00	12.00	2.40
24	CALIFORNIA AVE SUB, Fresno	Distribution	115.00	12.00	7.20
25	CALISTOGA SUB, Calistoga	Distribution	60.00	12.00	7.20
26	CALPELLA SUB, Calpella	Distribution	115.00	12.00	7.20
27	CAMDEN SUB, Riverdale	Distribution	70.00	12.00	2.40
28	CAMP EVERS SUB, Santa Cruz	Distribution	115.00	21.00	7.20
29	CAMPHORA SUB, Monterey	Distribution	60.00	12.00	7.20
30	CAMPHORA SUB, Monterey	Distribution	60.00	4.00	
31	CANAL SUB, Los Banos	Distribution	70.00	12.00	7.20
32	CANTUA SUB, Cantua Creek	Distribution	115.00	12.00	
33	CAPAY SUB, Orland	Distribution	60.00	12.00	2.40
34	CARBONA SUB, Tracy	Distribution	60.00	12.00	7.20
35	CARNATION SUB, Bakersfield	Distribution	70.00	21.00	7.20
36	CARNERAS SUB, Blackwells Corner	Distribution	70.00	12.00	7.20
37	CAROLANDS SUB, Hillsborough	Distribution	60.00	4.00	
38	CARQUINEZ SUB, Vallejo	Distribution	115.00	12.00	2.40
39	CARUTHERS SUB, Fresno	Distribution	70.00	12.00	2.40
40	CASSIDY SUB, Madera	Distribution	70.00	12.00	2.40

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	CASTRO VALLEY SUB, Castro Valley	Distribution	230.00	12.00	
2	CASTROVILLE SUB, Castroville	Distribution	115.00	21.00	7.20
3	CATLETT SUB, Pleasant Grove	Distribution	60.00	12.00	
4	CAWELO B SUB, Famosa	Distribution	70.00	4.00	
5	CAYETANO SUB, Danville	Distribution	230.00	21.00	7.20
6	CAYUCOS SUB, Cayucos	Distribution	70.00	12.00	7.20
7	CHANNEL SUB, Stockton	Distribution	60.00	12.00	
8	CHARCA SUB, Wasco	Distribution	115.00	12.00	7.20
9	CHEROKEE SUB, Stockton	Distribution	60.00	12.00	7.20
10	CHICO A SUB, Chico	Distribution	60.00	12.00	7.20
11	CHICO B SUB, Chico	Distribution	115.00	12.00	7.20
12	CHOLAME SUB, Cholame/93431	Distribution	70.00	12.00	2.40
13	CHOLAME SUB, Cholame/93431	Distribution	70.00	21.00	2.40
14	CHOWCHILLA SUB, Chowchilla	Distribution	115.00	12.00	7.20
15	CLARK ROAD SUB, Paradise	Distribution	60.00	12.00	2.40
16	CLARKSVILLE SUB, Clarksville	Distribution	115.00	21.00	7.20
17	CLAY SUB, lone	Distribution	60.00	12.00	2.40
18	CLAYTON SUB, Concord	Distribution	115.00	21.00	7.20
19	CLAYTON SUB, Concord	Distribution	115.00	12.00	7.20
20	CLEAR LAKE SUB, Finley	Distribution	60.00	12.00	2.40
21	CLOVERDALE SUB, Cloverdale	Distribution	115.00	12.00	7.20
22	CLOVIS SUB, Clovis	Distribution	115.00	12.00	7.20
23	CLOVIS SUB, Clovis	Distribution	115.00	21.00	7.20
24	COALINGA #1 SUB, Coalinga	Distribution	70.00	12.00	7.20
25	COALINGA #2 SUB, Coalinga	Distribution	70.00	12.00	2.40
26	COARSEGOLD SUB, Coursegold	Distribution	115.00	21.00	7.20
27	COLUMBUS SUB, Bakersfield	Distribution	115.00	12.00	7.20
28	COLUSA JUNCT SUB, Colusa	Distribution	60.00	12.00	7.20
29	COLUSA SUB, Colusa	Distribution	60.00	12.00	
30	CONTRA COSTA SUBSTATION, Antioch	Transmission	230.00	21.00	7.20
31	CONTRA COSTA SUBSTATION, Antioch	Transmission	115.00	21.00	6.60
32	COPPERMINE SUB, Clovis	Distribution	70.00	12.00	2.40
33	COPUS SUB, Bakersfield	Distribution	70.00	12.00	
34	CORCORAN SUB, Corcoran	Transmission	115.00	12.00	7.20
35	CORDELIA SUB, Cordelia	Distribution	115.00	12.00	7.20
36	CORDELIA SUB, Cordelia	Distribution	60.00	12.00	2.40
37	CORNING SUB, Corning	Distribution	60.00	12.00	2.40
38	CORONA SUB,	Distribution	115.00	12.00	7.20
39	CORRAL SUB, Bellota	Distribution	60.00	12.00	7.20
40	CORTINA SUB, Williams	Transmission	115.00	12.00	7.20

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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	COTATI SUB, Cotati	Distribution	60.00	12.00	
2	COTTLE SUB, Oakdale	Distribution	230.00	17.00	
3	COTTONWOOD SUB, Cottonwood	Transmission	115.00	12.00	7.20
4	COUNTRY CLUB SUB, Stockton	Distribution	60.00	12.00	
5	COUNTRY CLUB SUB, Stockton	Distribution	60.00	4.00	
6	CRESSEY SUB, Merced	Distribution	115.00	21.00	
7	CURTIS SUB, Sonora	Distribution	115.00	18.00	
8	CUYAMA SUB, Cuyama	Distribution	70.00	12.00	
9	CUYAMA SUB, Cuyama	Distribution	70.00	21.00	7.20
10	CYMRIC SUB, McKittrick	Distribution	115.00	12.00	7.20
11	DAIRYLAND SUB, Chowchilla	Distribution	115.00	12.00	7.20
12	DALY CITY SUB, Daly City	Distribution	115.00	12.00	7.20
13	DAVIS SUB, Davis	Distribution	115.00	12.00	7.20
14	DEEPWATER SUB, W. Sacramento	Distribution	115.00	12.00	7.20
15	DEL MAR SUB, Rocklin	Distribution	60.00	21.00	7.20
16	DEL MAR SUB, Rocklin	Distribution	60.00	12.00	7.20
17	DEL MONTE SUB, Monterey	Transmission	115.00	21.00	7.20
18	DERRICK SUB, Kettleman	Distribution	70.00	12.00	2.40
19	DESCHUTES SUB, Palo Cedro	Distribution	60.00	12.00	7.20
20	DIAMOND SPRINGS SUB, Placerville	Distribution	115.00	12.00	7.20
21	DINUBA SUB, Dinuba	Distribution	70.00	12.00	7.20
22	DIVIDE SUB, Orcutt	Transmission	70.00	12.00	2.40
23	DIVIDE SUB, Orcutt	Transmission	115.00	12.00	7.20
24	DIXON LANDING SUB,	Distribution	115.00	21.00	7.20
25	DIXON SUB, Dixon	Distribution	60.00	12.00	
26	DOLAN ROAD SUB, Moss Landing	Distribution	115.00	12.00	
27	DOS PALOS SUB, Dos Palos	Distribution	70.00	12.00	7.20
28	DUMBARTON SUB, Fremont	Distribution	115.00	12.00	
29	DUNBAR SUB, Glen Ellen	Distribution	60.00	12.00	
30	EAST GRAND SUB, So San Fran.	Distribution	115.00	12.00	7.20
31	EAST MARYSVILLE SUB, Marysville,	Distribution	115.00	12.00	7.20
32	EAST NICOLAUS SUB, E. Nicolaus	Transmission	115.00	12.00	
33	EAST STOCKTON SUB, Stockton	Distribution	60.00	12.00	7.20
34	EAST STOCKTON SUB, Stockton	Distribution	60.00	4.00	
35	EDENVALE SUB, San Jose	Distribution	115.00	21.00	7.20
36	EDENVALE SUB, San Jose	Distribution	115.00	12.00	7.20
37	EDES SUB, Oakland	Distribution	115.00	12.00	7.20
38	EEL RIVER SUB, Ferndale	Distribution	60.00	12.00	7.20
39	EIGHT MILE SUB, Stockton	Distribution	230.00	21.00	7.20
40	EL CAPITAN SUB, Snelling	Distribution	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	EL CAPITAN SUB, Snelling	Distribution	115.00	21.00	
2	EL CERRITO G SUB, El Cerrito	Distribution	115.00	12.00	
3	EL NIDO SUB, Merced	Distribution	115.00	12.00	7.20
4	EL PATIO SUB, Campbell	Distribution	115.00	12.00	7.20
5	EL PECO SUB, Madera	Distribution	70.00	12.00	
6	ELECTRA SUB,	Distribution	60.00	12.00	
7	ELK HILLS SUB, Valley Acres	Distribution	70.00	12.00	
8	ELK SUB, Elk	Distribution	60.00	12.00	2.40
9	EUREKA A SUB, Eureka	Distribution	60.00	12.00	7.20
10	EUREKA E SUB, Eureka	Distribution	60.00	12.00	
11	EVERGREEN SUB, San Jose	Transmission	115.00	21.00	7.20
12	FAIRHAVEN SUB, Fairhaven	Distribution	60.00	12.00	7.20
13	FAIRVIEW SUB, Martinez	Distribution	115.00	21.00	12.00
14	FAIRWAY SUB, Santa Maria	Distribution	115.00	12.00	7.20
15	FAMOSO SUB, Famosa	Distribution	115.00	12.00	
16	FELLOWS SUB, Fellows	Distribution	115.00	21.00	
17	FIGARDEN SUB, Fresno	Distribution	230.00	21.00	7.20
18	FIREBAUGH SUB, Firebaugh	Distribution	70.00	12.00	7.20
19	FITCH MOUNTAIN SUB, Healdsburg	Distribution	60.00	12.00	7.20
20	FLINT SUB, Auburn	Distribution	115.00	12.00	7.20
21	FMC SUB, San Jose	Distribution	115.00	12.00	7.20
22	FOOTHILL SUB, SLO	Distribution	115.00	12.00	2.40
23	FORESTHILL SUB, Foresthill,	Distribution	60.00	12.00	7.20
24	FORT BRAGG A SUB, Fort Bragg	Distribution	60.00	12.00	
25	FORT ORD SUB, Fort Ord	Distribution	60.00	21.00	7.20
26	FORT ORD SUB, Fort Ord	Distribution	60.00	12.00	2.40
27	FRANKLIN SUB, Hercules	Distribution	60.00	12.00	7.20
28	FREMONT SUB, Fremont	Distribution	115.00	12.00	7.20
29	FRENCH CAMP SUB, Stockton	Distribution	60.00	12.00	
30	FROGTOWN SUB, Angels Camp	Distribution	115.00	17.00	
31	FRUITVALE SUB, Bakersfield	Distribution	70.00	12.00	2.40
32	FULTON SUB, Fulton	Transmission	230.00	12.00	7.20
33	GABILAN SUB, Salinas	Distribution	115.00	12.00	7.20
34	GALLO SUB, Livingston	Distribution	115.00	12.00	
35	GANSNER SUB, Quincy	Distribution	60.00	12.00	7.20
36	GANSO SUB, Buttonwillow	Distribution	115.00	12.00	7.20
37	GARBERVILLE SUB, Garberville	Distribution	60.00	12.00	7.20
38	GATES SUB, Huron	Transmission	230.00	12.00	7.20
39	GATES SUB, Huron	Transmission	115.00	12.00	
40	GEYSERVILLE SUB, Geyserville	Distribution	60.00	12.00	2.40

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			Primary (c)	Secondary (d)	Tertiary (e)
1	GIFFEN SUB, San Joaquin	Distribution	70.00	12.00	2.40
2	GIRVAN SUB, Redding	Distribution	60.00	12.00	7.20
3	GLENN SUB, Orland	Transmission	60.00	12.00	
4	GLENWOOD SUB, Menlo Park	Distribution	60.00	12.00	7.20
5	GLENWOOD SUB, Menlo Park	Distribution	60.00	4.00	
6	GOLDTREE SUB, SLO	Distribution	115.00	12.00	7.20
7	GONZALES SUB, Gonzales	Distribution	60.00	12.00	
8	GOOSE LAKE SUB, Wasco	Distribution	115.00	12.00	7.20
9	GRAND ISLAND SUB, Ryde	Distribution	115.00	21.00	7.20
10	GRANT SUB, San Lorenzo	Distribution	115.00	12.00	7.20
11	GRASS VALLEY SUB, Grass Valley	Distribution	60.00	12.00	
12	GREEN VALLEY SUB, Watsonville	Transmission	115.00	21.00	7.20
13	GREENBRAE SUB, Larkspur	Distribution	60.00	12.00	7.20
14	GUALALA SUB, Gualala	Distribution	60.00	12.00	2.40
15	GUERNSEY SUB, Hanford	Distribution	70.00	12.00	
16	GUSTINE SUB, Gustine	Distribution	60.00	12.00	7.20
17	HALF MOON BAY SUB, Half Moon Bay	Distribution	60.00	12.00	2.40
18	HAMMER SUB, Stockton	Distribution	60.00	12.00	7.20
19	HAMMONDS SUB, Fresno	Distribution	115.00	12.00	
20	HARDING SUB, Stockton	Distribution	60.00	4.00	
21	HARDWICK SUB, Layton	Distribution	70.00	12.00	7.20
22	HARRIS SUB, Eureka	Distribution	60.00	12.00	7.20
23	HARTER SUB, Yuba City	Distribution	60.00	12.00	7.20
24	HARTLEY SUB, Lakeport	Distribution	60.00	12.00	7.20
25	HATTON SUB, Carmel Valley	Distribution	60.00	12.00	2.40
26	HENRIETTA SUB, Lemoore	Transmission	70.00	12.00	2.40
27	HERDLYN SUB, Tracy	Transmission	60.00	12.00	2.40
28	HICKS SUB, San Jose	Distribution	230.00	21.00	7.20
29	HICKS SUB, San Jose	Distribution	230.00	12.00	7.20
30	HIGGINS SUB, Higgins Corner	Distribution	115.00	12.00	7.20
31	HIGHLANDS SUB, Clear Lake	Distribution	115.00	12.00	7.20
32	HIGHWAY SUB, Petaluma	Distribution	115.00	12.00	7.20
33	HOLLISTER SUB, Hollister	Distribution	115.00	21.00	7.20
34	HOLLISTER SUB, Hollister	Distribution	60.00	21.00	
35	HONCUT SUB, Honcut	Distribution	115.00	12.00	7.20
36	HOPLAND SUB, Hopland	Transmission	60.00	12.00	2.40
37	HORSESHOE SUB, Granite Bay	Distribution	115.00	12.00	7.20
38	HOWLAND ROAD SUB, Manteca	Distribution	115.00	12.00	7.20
39	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	13.80	
40	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	13.80	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	12.00	7.20
2	HUMBOLDT BAY PP SUB, Eureka	Distribution	60.00	2.00	
3	HUMBOLDT BAY PP SUB, Eureka	Distribution	115.00	2.00	
4	HURON SUB, Huron	Distribution	70.00	12.00	2.40
5	IGNACIO SUB, Ignacio	Transmission	115.00	12.00	
6	IMHOFF SUB, Martinez	Distribution	115.00	12.00	7.20
7	IONE SUB, Ione	Distribution	60.00	12.00	7.20
8	JACINTO SUB, Willows	Distribution	60.00	12.00	7.20
9	JACOBS CORNER SUB, Lemoore	Distribution	70.00	12.00	2.40
10	JAMESON SUB, CORDELIA	Distribution	115.00	12.00	7.20
11	JANES CREEK SUB, Arcata	Distribution	60.00	12.00	7.20
12	JARVIS SUB, Union City	Distribution	115.00	12.00	7.20
13	JESSUP SUB, Anderson	Distribution	115.00	12.00	
14	JOLON SUB, King City	Distribution	60.00	12.00	
15	KELSO SUB, Tracy	Distribution	230.00	12.00	
16	KERMAN SUB, Kerman	Distribution	70.00	12.00	7.20
17	KERN OIL SUB, Bakersfield	Distribution	115.00	12.00	7.20
18	KERN PP DIST SUB, Bakersfield	Distribution	115.00	21.00	7.20
19	KESWICK SUB, Keswick	Distribution	60.00	12.00	2.40
20	KETTLEMAN HILLS SUB, Kettleman	Distribution	70.00	12.00	2.40
21	KING CITY SUB, King City	Distribution	60.00	12.00	
22	KINGSBURG SUB, Kingsburg	Transmission	115.00	12.00	7.20
23	KIRKER SUB, Pittsburg	Distribution	115.00	21.00	7.20
24	KONOCTI SUB, Clear Lake	Distribution	60.00	12.00	2.40
25	LAKEVIEW SUB, Bakersfield	Distribution	70.00	12.00	2.40
26	LAKEVILLE SUB, Petaluma	Transmission	115.00	12.00	7.20
27	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	21.00	7.20
28	LAKEWOOD SUB, Walnut Creek	Distribution	115.00	12.00	7.20
29	LAMMERS SUB, TRACY	Distribution	115.00	12.00	7.20
30	LAMONT SUB, Bakersfield	Distribution	115.00	12.00	
31	LAS GALLINAS A SUB, Las Gallinas	Distribution	115.00	12.00	7.20
32	LAS PALMAS SUB, Fresno	Distribution	115.00	12.00	7.20
33	LAS POSITAS SUB, Livermore	Transmission	230.00	21.00	7.20
34	LAS PULGAS SUB, Redwood City	Distribution	60.00	4.00	2.40
35	LAWRENCE SUB, Sunnyvale	Distribution	115.00	12.00	7.20
36	LE GRAND SUB, Le Grand	Distribution	115.00	12.00	7.20
37	LEMOORE SUB, Armonia	Distribution	70.00	12.00	2.40
38	LERDO SUB, Bakersfield	Distribution	115.00	12.00	7.20
39	LINCOLN SUB, Lincoln	Distribution	115.00	12.00	7.20
40	LINDEN SUB, Linden	Distribution	60.00	12.00	2.40

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			Primary (c)	Secondary (d)	Tertiary (e)
1	LIVE OAK SUB, Live Oak	Distribution	60.00	12.00	
2	LIVERMORE SUB, Livermore	Distribution	60.00	12.00	2.40
3	LIVINGSTON SUB, Livingston	Distribution	115.00	12.00	7.20
4	LIVINGSTON SUB, Livingston	Distribution	70.00	12.00	
5	LLAGAS SUB, Gilroy	Distribution	115.00	21.00	12.00
6	LOCKEFORD SUB, Lockeford	Transmission	115.00	21.00	7.20
7	LOCKHEED #1 SUB, Sunnyvale	Distribution	115.00	12.00	7.20
8	LOCKHEED #2 SUB, Sunnyvale	Distribution	115.00	12.00	
9	LODI SUB, Lodi	Distribution	60.00	12.00	2.40
10	LODI SUB, Lodi	Distribution	60.00	4.00	
11	LOGAN CREEK SUB, Willows	Distribution	230.00	21.00	
12	LONETREE SUB, Antioch	Distribution	230.00	21.00	7.20
13	LOS ALTOS SUB, Los Altos	Distribution	60.00	12.00	
14	LOS COCHES SUB, Greenfield	Distribution	60.00	12.00	
15	LOS GATOS SUB, Los Gatos	Distribution	60.00	12.00	7.20
16	LOS MOLINOS SUB, Los Molinos	Distribution	60.00	12.00	7.20
17	LOS OSITOS SUB, Monterey	Distribution	60.00	21.00	7.20
18	LOYOLA SUB, Loyola	Distribution	60.00	12.00	7.20
19	LOYOLA SUB, Loyola	Distribution	60.00	4.00	2.40
20	LUCERNE SUB, Lucerne	Distribution	115.00	12.00	7.20
21	MABURY SUB, San Jose	Distribution	60.00	12.00	2.40
22	MABURY SUB, San Jose	Distribution	60.00	12.00	7.20
23	MADERA SUB, Madera	Distribution	70.00	12.00	
24	MADISON SUB, Madison	Distribution	60.00	12.00	7.20
25	MADISON SUB, Madison	Distribution	115.00	12.00	
26	MAGUNDEN SUB, Bakersfield	Distribution	115.00	12.00	7.20
27	MAGUNDEN SUB, Bakersfield	Distribution	115.00	21.00	7.20
28	MALAGA SUB, Fresno	Distribution	115.00	12.00	7.20
29	MANCHESTER SUB, Fresno	Distribution	115.00	12.00	7.20
30	MANTECA SUB, Manteca	Transmission	115.00	17.00	
31	MARICOPA SUB, Maricopa	Distribution	70.00	12.00	2.40
32	MARIPOSA SUB, Mariposa	Distribution	70.00	21.00	
33	MARTELL SUB, Martell	Distribution	60.00	12.00	2.40
34	MARYSVILLE SUB, Marysville	Distribution	60.00	12.00	
35	MAXWELL SUB, Maxwell	Distribution	60.00	12.00	
36	MCARTHUR SUB, McArthur	Distribution	60.00	12.00	2.40
37	MCCALL SUB, Selma	Transmission	115.00	12.00	7.20
38	MCDONALD-MCDONALDISLAND SUB, Stockton	Distribution	60.00	4.00	2.40
39	MCFARLAND SUB, McFarland	Distribution	70.00	12.00	7.20
40	MCKEE SUB, San Jose	Distribution	115.00	12.00	7.20

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MCKITTRICK SUB, MCKITTRICK	Distribution	70.00	12.00	
2	MCMULLIN SUB, Fresno	Distribution	230.00	12.00	7.20
3	MEADOW LANE SUB, Concord	Distribution	115.00	21.00	7.20
4	MENDOCINO SUB, Redwood Valley	Transmission	60.00	12.00	2.40
5	MENDOTA SUB, Mendota	Transmission	115.00	12.00	7.20
6	MENLO SUB, Menlo Park	Distribution	60.00	12.00	7.20
7	MENLO SUB, Menlo Park	Distribution	60.00	4.00	
8	MERCED SUB, Merced	Transmission	115.00	12.00	7.20
9	MERCED SUB, Merced	Transmission	115.00	21.00	7.20
10	MERIDIAN SUB, Meridian	Distribution	60.00	12.00	
11	MESA SUB, Nipomo	Transmission	230.00	12.00	
12	METTLER SUB, Stockton	Distribution	60.00	12.00	
13	MIDDLETOWN SUB, Middletown	Distribution	60.00	12.00	7.20
14	MIDWAY SUB, Buttonwillow	Transmission	115.00	12.00	7.20
15	MILLBRAE SUB, Millbrae	Transmission	115.00	12.00	
16	MILLBRAE SUB, Millbrae	Transmission	60.00	4.00	
17	MILPITAS SUB, Milpitas	Distribution	115.00	21.00	7.20
18	MILPITAS SUB, Milpitas	Distribution	115.00	12.00	7.20
19	MIRABEL SUB, Forestville	Distribution	60.00	12.00	
20	MI-WUK SUB, Sugarpine	Distribution	115.00	17.00	
21	MOLINO SUB, Sebastopol	Distribution	60.00	12.00	7.20
22	MONROE SUB, Santa Rosa	Distribution	115.00	21.00	7.20
23	MONROE SUB, Santa Rosa	Distribution	115.00	12.00	7.20
24	MONTAGUE SUB, San Jose	Distribution	115.00	21.00	7.20
25	MONTE RIO SUB, Monte Rio	Distribution	60.00	12.00	7.20
26	MONTEREY SUB, Monterey	Distribution	60.00	4.00	
27	MORAGA SUB, Orinda	Transmission	115.00	12.00	
28	MORGAN HILL SUB, Morgan Hill	Distribution	115.00	21.00	7.20
29	MORMON SUB, Stockton	Distribution	60.00	12.00	7.20
30	MORRO BAY PP SWYD, Morro Bay	Transmission	115.00	12.00	7.20
31	MOSHER SUB, Stockton	Distribution	60.00	21.00	7.20
32	MOUNTAIN VIEW SUB, Mt. View	Distribution	115.00	12.00	7.20
33	MT. EDEN SUB, Hayward	Distribution	115.00	12.00	7.20
34	MT. QUARRIES SUB, Cool	Distribution	60.00	12.00	7.20
35	NAPA SUB, Napa	Distribution	60.00	12.00	
36	NARROWS SUB,	Distribution	60.00	21.00	7.20
37	NEWARK DIST SUB, Fremont	Distribution	230.00	21.00	7.20
38	NEWARK SUB, Fremont	Transmission	115.00	12.00	7.20
39	NEWBURG SUB, Fortuna	Distribution	60.00	12.00	2.40
40	NEWHALL SUB, Firebaugh	Distribution	115.00	12.00	7.20

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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	NEWMAN SUB, Newman	Distribution	60.00	12.00	7.20
2	NORCO SUB, Bakersfield	Distribution	115.00	12.00	7.20
3	NORD SUB, Chico	Distribution	115.00	12.00	7.20
4	NORTECH SUB, San Jose	Distribution	115.00	21.00	7.20
5	NORTH DUBLIN SUB, Pleasanton	Distribution	230.00	21.00	12.00
6	NORTH TOWER SUB, Vallejo	Distribution	115.00	12.00	7.20
7	NOTRE DAME SUB, Chico	Distribution	115.00	12.00	7.20
8	NOVATO SUB, Novato	Distribution	60.00	12.00	7.20
9	OAKHURST SUB, Oakhurst	Distribution	115.00	12.00	2.40
10	OAKLAND C (OAKLAND PP) SUB, Oakland	Distribution	115.00	12.00	7.20
11	OAKLAND D SUB, Oakland	Distribution	115.00	12.00	7.20
12	OAKLAND J SUB, Oakland	Distribution	115.00	12.00	7.20
13	OAKLAND K (CLAREMONT) SUB, Oakland	Distribution	115.00	12.00	6.60
14	OAKLAND L SUB, Oakland	Distribution	115.00	12.00	7.20
15	OAKLAND X SUB, Oakland	Distribution	115.00	12.00	7.20
16	OCEANO SUB, Oceano	Distribution	115.00	12.00	7.20
17	OILFIELDS SUB, San Ardo	Distribution	60.00	12.00	
18	OLD KEARNEY SUB, Fresno	Distribution	70.00	12.00	13.20
19	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	2.40
20	OLD RIVER SUB, Knob Hill	Distribution	70.00	12.00	7.20
21	OLETA SUB, Plymouth	Distribution	60.00	12.00	2.40
22	OLIVEHURST SUB, Olivehurst	Distribution	115.00	12.00	7.20
23	OREGON TRAIL SUB, Redding	Distribution	115.00	12.00	7.20
24	OREGON TRAIL SUB, Redding	Distribution	60.00	12.00	2.40
25	ORLAND B SUB, Orland	Distribution	60.00	12.00	2.40
26	ORO FINO SUB, Magalia	Distribution	60.00	12.00	2.40
27	ORO LOMA SUB, Dos Palos	Transmission	70.00	12.00	2.40
28	ORO LOMA SUB, Dos Palos	Transmission	115.00	12.00	
29	OROSI SUB, Orosi	Distribution	70.00	12.00	7.20
30	OROVILLE SUB, Oroville	Distribution	60.00	12.00	7.20
31	OROVILLE SUB, Oroville	Distribution	60.00	4.00	2.40
32	ORTIGA SUB, Los Banos	Distribution	70.00	12.00	2.40
33	PACIFICA SUB, Pacifica	Distribution	60.00	12.00	
34	PALMER SUB, Sisquat	Distribution	115.00	12.00	7.20
35	PANAMA SUB, Bakersfield	Distribution	70.00	21.00	7.20
36	PANOCHES SUB, Mendota	Transmission	230.00	12.00	7.20
37	PANORAMA SUB, Anderson	Distribution	115.00	12.00	
38	PARADISE SUB, Paradise	Distribution	60.00	12.00	7.20
39	PARADISE SUB, Paradise	Distribution	115.00	12.00	
40	PARKWAY SUB, Vallejo	Distribution	230.00	12.00	7.20

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			Primary (c)	Secondary (d)	Tertiary (e)
1	PARLIER SUB, Parlier	Distribution	115.00	12.00	7.20
2	PASO ROBLES SUB, Paso Robles	Distribution	70.00	12.00	2.40
3	PAUL SWEET SUB, Santa Cruz	Distribution	115.00	21.00	7.20
4	PEABODY SUB, Fairfield	Distribution	230.00	21.00	7.20
5	PEACHTON SUB, Gridley	Distribution	60.00	12.00	2.40
6	PEASE SUB, Tierra Buena	Transmission	115.00	12.00	
7	PENNGROVE SUB, Penngrove	Distribution	115.00	12.00	
8	PENRYN SUB, Penryn	Distribution	60.00	12.00	7.20
9	PEORIA SUB, Jamestown	Distribution	115.00	18.00	
10	PETALUMA C SUB, Petaluma	Distribution	60.00	12.00	
11	PIERCY SUB, San Jose	Distribution	115.00	21.00	7.20
12	PINE GROVE SUB, Pine Grove	Distribution	60.00	12.00	2.40
13	PINEDALE SUB, FRESNO	Distribution	115.00	21.00	7.20
14	PLACER SUB, Auburn	Transmission	115.00	12.00	
15	PLACERVILLE SUB, Placerville	Distribution	115.00	12.00	7.20
16	PLACERVILLE SUB, Placerville	Distribution	115.00	21.00	
17	PLAINFIELD SUB, Davis	Distribution	60.00	12.00	2.40
18	PLEASANT GROVE SUB, Pleasant Grove	Distribution	60.00	21.00	7.20
19	PLUMAS SUB, Wheatland	Distribution	60.00	21.00	7.20
20	PLUMAS SUB, Wheatland	Distribution	60.00	12.00	7.20
21	POINT MORETTI SUB, Davenport	Distribution	60.00	12.00	2.40
22	POINT PINOLE SUB, Richmond	Distribution	115.00	12.00	6.60
23	POSO MOUNTAIN SUB, Kern	Distribution	115.00	21.00	
24	PRUNEDALE SUB, Prunedale	Distribution	115.00	12.00	7.20
25	PUEBLO SUB, Napa	Distribution	115.00	12.00	
26	PUEBLO SUB, Napa	Distribution	115.00	21.00	
27	PURISIMA SUB, Lompoc	Distribution	115.00	12.00	7.20
28	PUTAH CREEK SUB, Winters	Distribution	115.00	12.00	
29	RACE TRACK SUB, Jamestown	Distribution	115.00	17.00	
30	RADUM SUB, Pleasanton	Distribution	60.00	12.00	
31	RAINBOW SUB, Sanger	Distribution	115.00	12.00	7.20
32	RALSTON SUB, Belmont	Distribution	60.00	12.00	
33	RANCHERS COTTON SUB, Fresno	Distribution	115.00	12.00	7.20
34	RAWSON SUB, Red Bluff	Distribution	60.00	12.00	2.40
35	RED BLUFF SUB, Red Bluff	Distribution	60.00	12.00	2.40
36	REDBUD SUB, Clearlake Oaks	Distribution	115.00	12.00	7.20
37	REDWOOD CITY SUB, Redwood City	Distribution	60.00	12.00	7.20
38	REEDLEY SUB, Reedley	Transmission	115.00	12.00	7.20
39	REEDLEY SUB, Reedley	Transmission	70.00	12.00	2.40
40	RENFRO SUB, BAKERSFIELD	Distribution	115.00	12.00	7.20

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			Primary (c)	Secondary (d)	Tertiary (e)
1	RESEARCH SUB, San Ramon	Distribution	230.00	21.00	7.20
2	RESERVATION ROAD SUB, Salinas	Distribution	60.00	12.00	2.40
3	RICE SUB, Princeton	Distribution	60.00	12.00	4.16
4	RICHMOND R SUB, Richmond	Distribution	115.00	12.00	7.20
5	RINCON SUB, Santa Rosa	Distribution	115.00	12.00	
6	RIO BRAVO SUB, Shafter	Distribution	115.00	12.00	7.20
7	RIO DELL SUB, Rio Dell	Distribution	60.00	12.00	
8	RIPON SUB, Ripon	Distribution	115.00	17.00	
9	RISING RIVER SUB, Cassell,	Distribution	60.00	12.00	2.40
10	RIVER OAKS SUB, San Jose	Distribution	115.00	21.00	7.20
11	RIVERBANK SUB, Escalon	Distribution	115.00	12.00	
12	ROB ROY SUB, Watsonville	Distribution	115.00	21.00	7.20
13	ROCKLIN SUB, Rocklin	Distribution	60.00	12.00	7.20
14	ROSEDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
15	ROSSMOOR SUB, Walnut Creek	Distribution	230.00	12.00	
16	ROUGH & READY ISLAND SUB, Stockton	Distribution	60.00	12.00	7.20
17	SALINAS SUB, Salinas	Transmission	115.00	12.00	7.20
18	SALMON CREEK SUB, Bodega Bay	Distribution	60.00	12.00	2.40
19	SAN ARDO SUB, San Ardo	Distribution	60.00	12.00	
20	SAN BENITO SUB, San Benito	Distribution	115.00	21.00	7.20
21	SAN BERNARD SUB, Lamont	Distribution	70.00	12.00	2.40
22	SAN CARLOS SUB, San Carlos	Distribution	60.00	12.00	7.20
23	SAN CARLOS SUB, San Carlos	Distribution	60.00	4.00	2.40
24	SAN FRAN A (POTRERO PP) SUB, San Francisco	Transmission	115.00	12.00	7.20
25	SAN FRAN H (MARTIN) SUB, Daly City	Transmission	115.00	12.00	
26	SAN FRAN P-HUNTERS POINT SUB, San Francisco	Distribution	115.00	12.00	
27	SAN FRAN X (MISSION) SUB, San Francisco	Distribution	115.00	12.00	7.20
28	SAN FRAN Y (LARKIN) SUB, San Francisco	Distribution	115.00	12.00	7.20
29	SAN FRAN Z (Embarcadero), San Francisco	Distribution	230.00	34.50	7.20
30	SAN JOAQUIN SUB, San Joaquin	Distribution	70.00	12.00	7.20
31	SAN JOSE A SUB, San Jose	Distribution	115.00	4.00	7.20
32	SAN JOSE A SUB, San Jose	Distribution	115.00	12.00	
33	SAN JOSE B SUB, San Jose	Distribution	115.00	12.00	7.20
34	SAN LEANDRO U SUB, San Leandro	Distribution	115.00	12.00	
35	SAN LUIS OBISPO SUB, SLO	Transmission	115.00	12.00	7.20
36	SAN MATEO SUB, San Mateo	Transmission	115.00	21.00	
37	SAN MATEO SUB, San Mateo	Transmission	60.00	4.00	
38	SAN MIGUEL SUB, San Miguel	Distribution	70.00	12.00	7.20
39	SAN PABLO SUB, Richmond	Distribution	115.00	12.00	7.20
40	SAN RAFAEL SUB, San Rafael	Distribution	115.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	SAN RAMON SUB, San Ramon	Transmission	230.00	21.00	12.00
2	SANGER SUB, Fresno	Transmission	115.00	12.00	7.20
3	SANTA MARIA SUB, Santa Maria	Distribution	115.00	12.00	7.20
4	SANTA NELLA SUB, Santa Nella	Distribution	70.00	12.00	2.40
5	SANTA RITA SUB, Dos Palos	Distribution	70.00	12.00	2.40
6	SANTA ROSA A SUB, Santa Rosa	Distribution	115.00	12.00	7.20
7	SANTA YNEZ SUB, Santa Maria	Distribution	115.00	12.00	7.20
8	SARATOGA SUB, Saratoga	Distribution	230.00	12.00	7.20
9	SAUSALITO SUB, Sausalito	Distribution	60.00	12.00	2.40
10	SAUSALITO SUB, Sausalito	Distribution	60.00	4.00	
11	SCHINDLER SUB, Five Points	Transmission	115.00	12.00	7.20
12	SEMITROPIC SUB, Wasco	Transmission	115.00	12.00	7.20
13	SERRAMONTE SUB, Daly City	Distribution	115.00	12.00	
14	SHAFTER SUB, Shafter	Distribution	115.00	12.00	7.20
15	SHARON SUB, Chowchilla	Distribution	115.00	12.00	
16	SHEPARD SUB, Clovis	Distribution	115.00	21.00	7.20
17	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	21.00	7.20
18	SHINGLE SPRINGS SUB, Shingle Springs	Distribution	115.00	12.00	7.20
19	SHREDDER SUB, Redwood City	Distribution	115.00	4.00	6.60
20	SILVERADO SUB, St. Helena	Distribution	115.00	21.00	
21	SISQUOC SUB, Orcutt	Distribution	115.00	12.00	7.20
22	SMYRNA SUB, Wasco	Distribution	115.00	12.00	7.20
23	SNEATH LANE SUB, San Bruno	Distribution	60.00	12.00	2.40
24	SOBRANTE SUB, Orinda	Transmission	115.00	12.00	7.20
25	SOLEDAD SUB, Soledad	Transmission	60.00	12.00	
26	SONOMA A SUB, Sonoma	Distribution	115.00	12.00	
27	SOUTH BAY #1 & #2 SUB, Tracy	Distribution	60.00	4.00	
28	SPANISH CREEK SUB,	Distribution	60.00	44.00	
29	SPENCE SUB, Salinas	Distribution	60.00	12.00	
30	SRI SUB, Menlo Park	Distribution	60.00	12.00	
31	STAFFORD SUB, Novato	Distribution	60.00	12.00	
32	STAGG SUB, Stockton	Transmission	230.00	21.00	7.20
33	STAGG SUB, Stockton	Transmission	60.00	12.00	2.40
34	STELLING SUB, Cupertino	Distribution	115.00	12.00	7.20
35	STILLWATER STA SUB, Project City	Distribution	60.00	12.00	2.40
36	STOCKDALE SUB, Bakersfield	Distribution	230.00	21.00	7.20
37	STOCKDALE SUB, Bakersfield	Distribution	115.00	12.00	7.20
38	STOCKTON A SUB, Stockton	Distribution	115.00	12.00	
39	STOCKTON A SUB, Stockton	Distribution	60.00	4.00	
40	STONE CORRAL SUB, Woodlake	Distribution	70.00	12.00	2.40

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			Primary (c)	Secondary (d)	Tertiary (e)
1	STONE SUB, San Jose	Distribution	115.00	12.00	7.20
2	STOREY SUB, Madera	Distribution	230.00	12.00	7.20
3	STROUD SUB, Helm	Distribution	70.00	12.00	2.40
4	SUISUN SUB, Fairfield	Distribution	115.00	12.00	7.20
5	SUNOL SUB, Sunol	Distribution	60.00	12.00	7.20
6	SWIFT SUB, San Jose	Distribution	115.00	21.00	7.20
7	SYCAMORE CREEK SUB, Chico	Distribution	115.00	12.00	
8	TAFT SUB, Taft	Transmission	115.00	12.00	7.20
9	TAMARACK SUB, Soda Springs	Distribution	60.00	12.00	7.20
10	TASSAJARA SUB, Danville	Distribution	230.00	21.00	7.20
11	TEJON SUB, Lebec	Distribution	70.00	12.00	2.40
12	TEMBLOR SUB, McKittrick	Distribution	115.00	12.00	2.40
13	TEMPLETON SUB, TEMPLETON	Transmission	230.00	21.00	7.20
14	TEVIS SUB, Oildale	Distribution	115.00	21.00	7.20
15	TIDEWATER SUB, Martinez	Distribution	230.00	21.00	
16	TIVY VALLEY SUB, Fresno	Distribution	70.00	12.00	7.20
17	TRACY SUB, Tracy	Distribution	115.00	12.00	7.20
18	TRES VIAS SUB, Oroville	Distribution	60.00	12.00	7.20
19	TRIMBLE SUB, San Jose	Distribution	115.00	12.00	7.20
20	TRIMBLE SUB, San Jose	Distribution	115.00	21.00	7.20
21	TULARE LAKE SUB, Kettleman	Distribution	70.00	12.00	2.40
22	TULUCAY SUB, Napa	Transmission	60.00	12.00	7.20
23	TUPMAN SUB, Tupman	Distribution	115.00	12.00	7.20
24	TWISSELMAN SUB, Blackwell Corners	Distribution	70.00	12.00	7.20
25	TYLER SUB, Red Bluff	Distribution	60.00	12.00	2.40
26	UKIAH SUB, Ukiah	Distribution	115.00	12.00	7.20
27	URICH SUB, Martinez	Distribution	60.00	4.00	
28	VACA DIXON SUB, Vacaville	Transmission	115.00	12.00	7.20
29	VACAVILLE SUB, Vacaville	Distribution	115.00	12.00	7.20
30	VALLEY HOME SUB, Valley Home	Distribution	60.00	17.00	
31	VALLEY HOME SUB, Valley Home	Distribution	115.00	17.00	
32	VALLEY VIEW SUB, El Sobrante	Distribution	115.00	12.00	
33	VASCO SUB, Livermore	Distribution	60.00	12.00	
34	VASONA SUB, Los Gatos	Distribution	230.00	12.00	7.20
35	VICTOR SUB, Lodi	Distribution	60.00	12.00	2.40
36	VIEJO SUB, Monterey	Distribution	60.00	21.00	7.20
37	VIERRA SUB, Lathrop	Distribution	115.00	17.00	7.20
38	VINEYARD SUB, Pleasanton	Distribution	230.00	21.00	7.20
39	VOLTA #1PH SUB, Shingletown	Distribution	60.00	12.00	2.40
40	WAHTOKE SUB, Reedley	Distribution	115.00	12.00	7.20

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			Primary (c)	Secondary (d)	Tertiary (e)
1	WASCO SUB, Wasco	Distribution	70.00	12.00	2.40
2	WATERLOO SUB, Stockton	Distribution	60.00	12.00	2.40
3	WATSONVILLE SUB, Watsonville	Distribution	60.00	12.00	7.20
4	WATSONVILLE SUB, Watsonville	Distribution	60.00	4.00	
5	WEBER SUB, Stockton	Transmission	60.00	12.00	7.20
6	WEBER SUB, Stockton	Transmission	230.00	12.00	7.20
7	WEEDPATCH SUB, Weedpatch	Distribution	70.00	12.00	7.20
8	WELLFIELD SUB, Lamont	Distribution	70.00	12.00	2.40
9	WEST FRESNO SUB, Fresno	Distribution	115.00	12.00	7.20
10	WEST LANE SUB, Stockton	Distribution	60.00	12.00	7.20
11	WEST SACRAMENTO SUB, WEST SACRAMENTO	Distribution	115.00	12.00	7.20
12	WESTLEY SUB, Westley	Distribution	60.00	12.00	2.40
13	WESTPARK SUB, Bakersfield	Distribution	115.00	12.00	7.20
14	WHEATLAND SUB, Wheatland	Distribution	60.00	12.00	7.20
15	WHEELER RIDGE SUB, Bakersfield	Transmission	70.00	12.00	7.20
16	WHISMAN SUB, Mt. View	Distribution	115.00	12.00	7.20
17	WILLIAMS SUB, Williams	Distribution	60.00	12.00	7.20
18	WILLITS A SUB, Willits	Distribution	60.00	12.00	2.40
19	WILLOW CREEK SUB, Willow Creek	Distribution	60.00	12.00	2.40
20	WILLOW PASS SUB, Pittsburg	Distribution	115.00	21.00	7.20
21	WILLOW PASS SUB, Pittsburg	Distribution	60.00	12.00	2.40
22	WILLOWS A SUB, Willows	Distribution	60.00	12.00	
23	WILSON SUB, Merced	Transmission	115.00	12.00	
24	WINDSOR SUB, Windsor	Distribution	60.00	12.00	
25	WINTERS SUB, Winters	Distribution	60.00	12.00	
26	WOLFE SUB, Cupertino	Distribution	115.00	12.00	
27	WOODCHUCK SUB, Wilson Village	Distribution	70.00	21.00	
28	WOODLAND SUB, Woodland	Distribution	115.00	12.00	7.20
29	WOODSIDE SUB, Woodside	Distribution	60.00	12.00	
30	WOODWARD SUB, Fresno	Distribution	115.00	21.00	7.20
31	WRIGHT SUB, Los Banos	Distribution	70.00	12.00	2.40
32	WYANDOTTE SUB, Oroville	Distribution	115.00	12.00	7.20
33	ZACA SUB, Santa Maria	Distribution	115.00	12.00	7.20
34	ZAMORA SUB, Zamora	Distribution	115.00	12.00	
35	ALTAMONT SUB, Livermore	Distribution	60.00	4.00	
36	ANNAPOLIS SUB, Annapolis	Distribution	60.00	12.00	2.40
37	AUBURN SUB, Auburn	Distribution	60.00	12.00	2.40
38	BALFOUR SUB, Brentwood	Distribution	60.00	12.00	4.16
39	BANTA SUB, Tracy	Distribution	60.00	12.00	2.40
40	BARRY SUB, Barry	Distribution	60.00	12.00	7.20

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	BATAVIA SUB, Dixon	Distribution	60.00	12.00	2.40
2	BELLRIDGE 1A SUB, ButtonWillow	Distribution	115.00	4.00	
3	BELLRIDGE 1B SUB, ButtonWillow	Distribution	115.00	4.00	
4	BERESFORD SUB, San Mateo	Distribution	60.00	4.00	
5	BERRENDA C SUB, Keck's Corner	Distribution	70.00	12.00	2.40
6	BIG LAGOON SUB, Big Lagoon Park	Distribution	60.00	12.00	2.40
7	BIG RIVER SUB, Mendocino	Distribution	60.00	12.00	2.40
8	BOGARD SUB, Old Station	Distribution	60.00	12.00	
9	BONNIE NOOK SUB, Dutch Flat	Distribution	60.00	12.00	2.40
10	BORONDA SUB, Salinas	Distribution	60.00	12.00	2.40
11	BOSWELL SUB, Corcoran	Distribution	70.00	12.00	2.40
12	BRIDGEVILLE SUB, Bridgeville	Transmission	60.00	12.00	7.20
13	BROWNS VALLEY SUB, Browns Valley	Distribution	60.00	12.00	2.40
14	BURNEY SUB, Burney	Distribution	60.00	12.00	2.40
15	CAMBRIA SUB, Cambria	Distribution	70.00	12.00	2.40
16	CARLOTTA SUB, Carlotta	Distribution	60.00	12.00	2.40
17	CARRIZO PLAINS SUB, Carrizo Plains	Distribution	115.00	12.00	2.40
18	CAWELO C SUB, Famosa	Distribution	115.00	4.00	
19	CHESTER SUB, Plumas	Distribution	60.00	13.80	
20	CEDAR CREEK SUB, Round Mountain	Distribution	60.00	12.00	2.40
21	CELERON HILL SUB, N. Belridge	Distribution	70.00	12.00	
22	CHALLENGE SUB, Challenge	Distribution	60.00	12.00	2.40
23	COLONY SUB, Lodi	Distribution	60.00	12.00	2.40
24	COLUMBIA HILL SUB, Sweetland	Distribution	60.00	12.00	2.40
25	COVELO SUB, Covelo	Distribution	60.00	12.00	2.40
26	CROWS LANDING SUB, Crows Landing	Distribution	60.00	12.00	2.40
27	CRUSHER SUB, Bonny Doon	Distribution	60.00	4.00	
28	CRYSTAL SPRINGS SUB, San Mateo	Distribution	60.00	4.00	
29	DAIRYVILLE SUB, Dairyville	Distribution	60.00	12.00	2.40
30	DEVILS DEN SUB, Avenal	Distribution	70.00	12.00	2.40
31	DOBBINS SUB, Dobbins	Distribution	60.00	12.00	2.40
32	DRAKE SUB, Arbuckle	Distribution	60.00	2.00	2.40
33	DUNLAP SUB, Fresno	Distribution	70.00	12.00	
34	DUNNIGAN SUB, Dunnigan	Distribution	60.00	12.00	2.40
35	EAST QUINCY SUB, Quincy	Distribution	60.00	12.00	2.40
36	ELK CREEK SUB, Elk Creek	Distribution	60.00	12.00	2.40
37	EMERALD LAKE SUB, Emerald Lake	Distribution	60.00	4.00	2.40
38	ENCINAL SUB, Live Oak	Distribution	60.00	2.00	2.40
39	ERTA SUB, Watsonville	Distribution	60.00	4.00	
40	ESQUON SUB, Durham	Distribution	60.00	12.00	2.40

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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	FORT ROSS SUB, Fort Ross	Distribution	60.00	12.00	2.40
2	FORT SEWARD SUB, Fort Seward	Distribution	60.00	12.00	2.40
3	FRENCH GULCH SUB, French Gulch	Distribution	60.00	12.00	2.40
4	FRUITLAND SUB, Myers Flat	Distribution	60.00	12.00	2.40
5	GARCIA SUB, Point Arena	Distribution	60.00	4.00	2.40
6	GARDNER SUB, Taft	Distribution	70.00	4.00	
7	GERBER SUB, Gerber	Distribution	60.00	12.00	2.40
8	GRAYS FLAT SUB, Twain	Distribution	60.00	4.00	2.40
9	HAMILTON SUB,	Distribution	60.00	12.00	2.40
10	HARRINGTON SUB, Arbuckle	Distribution	60.00	2.00	
11	HILLSDALE SUB, San Mateo	Distribution	60.00	4.00	2.40
12	HOOPA SUB, Hoopa	Distribution	60.00	12.00	2.40
13	INDIAN FLAT SUB, Incline	Distribution	70.00	12.00	
14	INDUSTRIAL ACRES SUB, Salinas	Distribution	60.00	4.00	
15	IUKA SUB, Pleasanton	Distribution	60.00	4.00	
16	JACALITOS SUB,	Distribution	70.00	12.00	2.40
17	KANAKA SUB, Feather Falls	Distribution	115.00	12.00	7.20
18	KERN WATER SUB, Bakersfield	Distribution	115.00	4.00	
19	KNIGHTS LANDING SUB, Knights Landing	Distribution	115.00	12.00	
20	LAGUNITAS SUB, Salinas	Distribution	60.00	2.40	
21	LAURELES SUB, Carmel	Distribution	60.00	12.00	
22	LAYTONVILLE SUB, Laytonville,	Distribution	60.00	12.00	2.40
23	LEARNER SUB, Stockton	Distribution	60.00	4.00	
24	LIMESTONE SUB, Shingle Springs	Distribution	60.00	2.00	
25	LOST HILLS SUB, Blackwell Corners	Distribution	70.00	12.00	2.40
26	LOW GAP SUB, Mad River	Distribution	60.00	12.00	
27	MAINE PRAIRIE SUB, DIXON	Distribution	60.00	4.00	2.40
28	MANZANITA SUB, Seaside	Distribution	60.00	4.00	
29	MAPLE CREEK SUB, Blue Lake	Distribution	60.00	12.00	2.40
30	MARSH SUB, Brentwood	Distribution	60.00	12.00	2.40
31	MERCY SPRINGS SUB, Los Banos	Distribution	60.00	12.00	2.40
32	MIDDLE RIVER SUB, Stockton	Distribution	60.00	12.00	2.40
33	MONARCH SUB, Stockton	Distribution	60.00	4.00	2.40
34	MONTICELLO SUB, Winters	Distribution	115.00	12.00	
35	NAVY LAB SUB, Monterey	Distribution	60.00	4.00	
36	NAVY SCHOOL SUB, Monterey	Distribution	60.00	4.00	
37	NEW HOPE SUB, Lodi	Distribution	60.00	12.00	2.40
38	NORTH BRANCH SUB, San Andreas	Distribution	60.00	12.00	2.40
39	OAK PARK SUB, Stockton	Distribution	60.00	4.00	
40	OLEMA SUB, Olema	Distribution	60.00	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	ORICK SUB, Orick	Distribution	60.00	12.00	2.40
2	OTTER SUB, Carmel	Distribution	60.00	12.00	
3	PERRY SUB, Cambria	Distribution	70.00	12.00	2.40
4	PETALUMA A SUB, Petaluma	Distribution	60.00	4.00	2.40
5	PHILO SUB, Philo	Distribution	60.00	12.00	2.40
6	PIKE CITY SUB, Camptonville	Distribution	60.00	12.00	2.40
7	PITTSBURG SUB, Pittsburg	Distribution	60.00	4.00	2.40
8	POINT ARENA SUB, Pt Arena	Distribution	60.00	12.00	2.40
9	PORT COSTA BRICK SUB, Port Costa	Distribution	60.00	4.00	
10	RECLAMATION DIST#108 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
11	RECLAMATION DIST#1500 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
12	RECLAMATION DIST#2047 SUB, KNIGHTS LANDING	Distribution	60.00	2.00	
13	RESERVE OIL SUB, Hanford	Distribution	70.00	12.00	2.40
14	RESERVE OIL SUB, Hanford	Distribution	70.00	4.00	
15	RIDGE CABIN SUB,	Distribution	60.00	12.00	
16	RIVER ROCK SUB, Fresno	Distribution	70.00	12.00	2.40
17	RUSS RANCH SUB, Blue Lake	Distribution	60.00	12.00	
18	SAN ANDREAS SUB, Millbrae	Distribution	60.00	34.60	
19	SAN BRUNO SUB, San Bruno	Distribution	60.00	4.00	
20	SAN LUIS #3 SUB, Los Banos	Distribution	115.00	2.00	2.40
21	SAN LUIS #5 SUB, Los Banos	Distribution	115.00	2.00	2.40
22	SAND CREEK SUB, Oroshi	Distribution	70.00	12.00	
23	SHADY GLEN SUB, Colfax	Distribution	60.00	12.00	2.40
24	SKAGGS ISLAND SUB, Skaggs Island	Distribution	115.00	12.00	2.40
25	SMARTVILLE SUB, Smartville	Distribution	60.00	12.00	
26	STAUFFER SUB, Martinez	Distribution	60.00	4.00	
27	STOCKTON ACRES SUB, Stockton	Distribution	60.00	4.00	
28	SUMMIT SUB, Soda Springs	Distribution	60.00	12.00	2.40
29	TECUYA SUB, Bakersfield	Distribution	70.00	2.00	2.40
30	TERMINOUS SUB, Lodi	Distribution	60.00	12.00	
31	TOCALOMA SUB, Tocaloma	Distribution	60.00	4.00	
32	TRINIDAD SUB, Trinidad	Distribution	60.00	12.00	2.40
33	TUDOR SUB, Tudor	Distribution	60.00	12.00	
34	UPPER LAKE SUB, Upper Lake	Distribution	60.00	12.00	2.40
35	VALLECITOS SUB, Sunol	Distribution	60.00	12.00	
36	VINA SUB, Vina	Distribution	60.00	12.00	2.40
37	WATERSHED SUB, Redwood City	Distribution	60.00	4.00	
38	WEIMAR SUB, Weimar	Distribution	60.00	12.00	2.40
39	WEST SIDE SUB, Tracy	Distribution	60.00	2.00	
40	WESTLANDS SUB, San Joaquin	Distribution	70.00	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	WHITMORE SUB, Whitmore	Distribution	60.00	12.00	2.40
2	WILDWOOD SUB, Wildwood	Distribution	115.00	12.00	
3	WILKINS SLOUGH SUB, Arbuckle	Distribution	60.00	12.00	2.40
4	WOODACRE SUB, Woodacre	Distribution	60.00	12.00	
5	YOSEMITE PARK SUB,	Distribution	70.00	12.00	7.20
6	Rounding issues in column f		-130.00		-37.20
7	Total Distribution and Transmission Substations		91065.00	20080.90	4260.52
8	Transmission only Substations				
9					
10	Combined Dist Subs < 10MVA (130 substations)				
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SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
360	6	1	2.00000			1
334	4	1	2.00000			2
840	2		2.00000			3
80	3		1.00000			4
400	2		2.00000			5
400	2		2.00000			6
90	3	1	1.00000			7
840	2		2.00000			8
90	3	1	1.00000			9
76	3		1.00000			10
190	4	1	2.00000			11
214	6	1	2.00000			12
120	6	2	2.00000			13
180	3	1	1.00000			14
400	2		2.00000			15
90	3	1	1.00000			16
200	1		1.00000			17
588	4	2	2.00000			18
400	2		2.00000			19
240	6	1	2.00000			20
400	2		2.00000			21
170	6	1	2.00000			22
68	3	1	1.00000			23
400	2		2.00000			24
840	2		2.00000			25
80	3	1	1.00000			26
600	2		2.00000			27
823	4	1	2.00000			28
180	3	1	1.00000			29
			0.00000			30
2244	6	1	2.00000			31
255	4	1	2.00000			32
84	3		1.00000			33
840	2		2.00000			34
38	3		1.00000			35
134	3		1.00000			36
400	2		2.00000			37
180	3	1	1.00000			38
50	3	1	1.00000			39
1260	3		3.00000			40

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
40	1		1.00000			1
400	2		2.00000			2
400	2		2.00000			3
823	4	1	2.00000			4
400	2		2.00000			5
90	3	1	1.00000			6
400	2		2.00000			7
1260	3		3.00000			8
90	3	1	1.00000			9
400	2		2.00000			10
840	2		2.00000			11
90	3		1.00000			12
400	2		2.00000			13
334	4		2.00000			14
840	3	1	1.00000			15
840	2		2.00000			16
100	1	1	2.00000			17
1243	5	1	3.00000			18
280	4	1	2.00000			19
90	3	1	1.00000			20
50	3		1.00000			21
840	2		2.00000			22
3366	9	2	3.00000			23
1630	10	1	4.00000			24
1260	3		3.00000			25
3364	9	2	3.00000			26
90	3		1.00000			27
400	2		2.00000			28
			0.00000			29
1260	3		3.00000			30
1243	5	1	3.00000			31
269	3	1	1.00000			32
1680	4		2.00000			33
1122	3	1	1.00000			34
200	4	1	1.00000			35
80	3		1.00000			36
1646	8	1	4.00000			37
200	2		2.00000			38
168	3	1	1.00000			39
420	1		1.00000			40

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
840	2		2.00000			1
80	3	1	1.00000			2
840	2		2.00000			3
95	3		1.00000			4
823	4	1	2.00000			5
190	4	1	2.00000			6
254	6		2.00000			7
1122	3	1	1.00000			8
200	2		2.00000			9
400	2		2.00000			10
420	1		1.00000			11
100	1		1.00000			12
840	2		2.00000			13
200	1		1.00000			14
200	2		2.00000			15
1260	3		3.00000			16
90	3	1	1.00000			17
			0.00000			18
90	3	1	1.00000			19
90	3	1	1.00000			20
823	4	1	2.00000			21
75	6		2.00000			22
600	2		2.00000			23
1008	5	1	3.00000			24
1122	3	1	1.00000			25
162	4		2.00000			26
175	1		1.00000			27
806	6	1	2.00000			28
3366	9	2	3.00000			29
90	3	1	1.00000			30
400	2		2.00000			31
290	4	1	2.00000			32
1094	8		3.00000			33
2244	6	1	2.00000			34
334	4	1	2.00000			35
600	2		2.00000			36
60	3	1	1.00000			37
400	2		2.00000			38
689	4	1	2.00000			39
45	1		1.00000			40

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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
90	2		2.00000			1
27	2		2.00000			2
13	1		1.00000			3
60	2		2.00000			4
41	2		2.00000			5
49	4	1	2.00000			6
30	1		1.00000			7
19	3	1	1.00000			8
16	1		1.00000			9
38	2		2.00000			10
16	1		1.00000			11
11	3	1	1.00000			12
16	1		1.00000			13
16	1		1.00000			14
27	4	1	2.00000			15
60	2		2.00000			16
13	3	1	1.00000			17
210	3		3.00000			18
30	1		1.00000			19
90	2		2.00000			20
25	2		2.00000			21
16	3	1	1.00000			22
16	1		1.00000			23
112	2		2.00000			24
45	1		1.00000			25
225	3		3.00000			26
13	1		1.00000			27
120	3		3.00000			28
39	4		2.00000			29
90	2		2.00000			30
75	2		2.00000			31
16	1		1.00000			32
13	1		1.00000			33
57	2		2.00000			34
57	3		3.00000			35
16	6	1	2.00000			36
70	3		3.00000			37
135	3		3.00000			38
16	2		2.00000			39
11	3	1	1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
15	3		1.00000			1
20	3		1.00000			2
13	1		1.00000			3
13	3	1	1.00000			4
90	2		2.00000			5
13	1		1.00000			6
16	1		1.00000			7
30	1		1.00000			8
30	1		1.00000			9
225	3		3.00000			10
120	3		3.00000			11
90	3		3.00000			12
21	2		2.00000			13
76	3		3.00000			14
90	2		2.00000			15
45	1		1.00000			16
30	1		1.00000			17
75	2		2.00000			18
11	1		1.00000			19
20	3		1.00000			20
30	1		1.00000			21
15	3		1.00000			22
19	3		1.00000			23
135	3		3.00000			24
21	3	1	1.00000			25
16	1		1.00000			26
41	2		2.00000			27
90	2		2.00000			28
11	1		1.00000			29
6	3	1	1.00000			30
60	2		2.00000			31
24	1		1.00000			32
11	6		1.00000			33
37	3		2.00000			34
16	1		1.00000			35
16	1		1.00000			36
14	2		2.00000			37
25	2		2.00000			38
50	4		2.00000			39
45	1		1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
90	2		2.00000			1
30	3	1	1.00000			2
39	4	1	2.00000			3
11	1		1.00000			4
45	1		1.00000			5
25	2		2.00000			6
13	1		1.00000			7
41	2		2.00000			8
16	1		1.00000			9
21	3	1	1.00000			10
32	2		2.00000			11
13	1		1.00000			12
13	1		1.00000			13
61	2		2.00000			14
11	3	1	1.00000			15
135	3		3.00000			16
29	2		2.00000			17
135	3		3.00000			18
16	1		1.00000			19
20	6	1	2.00000			20
19	3	1	1.00000			21
90	2		2.00000			22
45	1		1.00000			23
27	2		2.00000			24
21	3		1.00000			25
61	2		2.00000			26
59	3		3.00000			27
12	1		1.00000			28
21	6	1	2.00000			29
225	3		3.00000			30
42	3	1	1.00000			31
20	3	1	1.00000			32
28	4		2.00000			33
46	2		2.00000			34
45	1		1.00000			35
13	3	2	1.00000			36
58	10	3	2.00000			37
30	1		1.00000			38
43	2		2.00000			39
7	1		1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
29	6	1	2.00000			1
130	3		3.00000			2
75	2		2.00000			3
35	3		3.00000			4
7	1		1.00000			5
30	1		1.00000			6
90	2		2.00000			7
19	3	1	1.00000			8
16	3		1.00000			9
16	1		1.00000			10
60	2		2.00000			11
135	3		3.00000			12
135	3		3.00000			13
90	2		2.00000			14
75	2		2.00000			15
16	1		1.00000			16
75	2		2.00000			17
14	1		1.00000			18
43	2		2.00000			19
61	2		2.00000			20
60	2		2.00000			21
11	3	1	1.00000			22
30	1		1.00000			23
135	3		3.00000			24
75	2		2.00000			25
11	1		1.00000			26
13	1		1.00000			27
105	3		3.00000			28
32	6	1	2.00000			29
180	4		4.00000			30
25	2	1	2.00000			31
16	1		1.00000			32
16	1		1.00000			33
8	1		1.00000			34
135	3		3.00000			35
45	1		1.00000			36
90	2		2.00000			37
25	4		2.00000			38
90	2		2.00000			39
63	2		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
45	1		1.00000			1
127	3		3.00000			2
46	2		2.00000			3
180	4		4.00000			4
23	2		2.00000			5
11	1		1.00000			6
13	1		1.00000			7
11	3	1	1.00000			8
13	1		1.00000			9
21	3	1	1.00000			10
90	2	1	2.00000			11
13	1		1.00000			12
50	3		1.00000			13
60	2		2.00000			14
30	1		1.00000			15
60	2		2.00000			16
225	3		3.00000			17
30	1		1.00000			18
22	2		2.00000			19
30	3		1.00000			20
50	2		2.00000			21
11	1		1.00000			22
21	3	1	1.00000			23
60	2		2.00000			24
45	1		1.00000			25
19	3	1	1.00000			26
60	2		2.00000			27
105	3		3.00000			28
32	2		2.00000			29
25	4		2.00000			30
49	4	1	2.00000			31
60	2		2.00000			32
16	1		1.00000			33
25	1		1.00000			34
13	1		1.00000			35
16	1		1.00000			36
21	3	1	1.00000			37
90	2		2.00000			38
			0.00000			39
22	4		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
19	3		1.00000			1
16	1		1.00000			2
30	1		1.00000			3
32	2		2.00000			4
7	1		1.00000			5
16	1		1.00000			6
22	2		2.00000			7
27	2		2.00000			8
81	3		3.00000			9
90	2		2.00000			10
19	3	1	1.00000			11
60	2		2.00000			12
32	2		2.00000			13
18	7	1	2.00000			14
60	2		2.00000			15
21	3		3.00000			16
50	5		3.00000			17
90	3		3.00000			18
16	1		1.00000			19
13	2		2.00000			20
12	1		1.00000			21
29	2		2.00000			22
60	2		2.00000			23
19	2		2.00000			24
16	3		1.00000			25
46	2		2.00000			26
13	1		1.00000			27
150	2		2.00000			28
90	2		2.00000			29
77	3		3.00000			30
60	2		2.00000			31
90	2		2.00000			32
70	2		2.00000			33
25	1		1.00000			34
16	1		1.00000			35
13	3	1	1.00000			36
90	2		2.00000			37
16	1		1.00000			38
133	6		2.00000			39
77	3		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
11	1		1.00000			1
4	1		1.00000			2
4	1		1.00000			3
20	3		1.00000			4
46	2		2.00000			5
16	1		1.00000			6
13	1		1.00000			7
16	1		1.00000			8
29	2		2.00000			9
90	2		2.00000			10
39	2		2.00000			11
105	3		3.00000			12
22	1		1.00000			13
27	2		2.00000			14
30	1		1.00000			15
60	2		2.00000			16
135	3		3.00000			17
90	2		2.00000			18
11	3	1	1.00000			19
11	3		1.00000			20
47	3		3.00000			21
90	2		2.00000			22
135	3		3.00000			23
23	2		2.00000			24
49	4		2.00000			25
75	2		2.00000			26
215	4		4.00000			27
25	3	1	1.00000			28
90	2		2.00000			29
75	2		2.00000			30
76	3		3.00000			31
30	1		1.00000			32
165	3		3.00000			33
14	2		2.00000			34
145	5	1	3.00000			35
45	1		1.00000			36
75	2		2.00000			37
90	2		2.00000			38
91	3		3.00000			39
21	3	1	1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
27	2		2.00000			1
25	6		2.00000			2
45	1		1.00000			3
11	3		1.00000			4
115	3		3.00000			5
30	1	1	1.00000			6
90	2		2.00000			7
46	2		2.00000			8
21	3	1	1.00000			9
5	3	1	1.00000			10
45	1		1.00000			11
45	1		1.00000			12
51	3		3.00000			13
13	3	1	1.00000			14
32	2		2.00000			15
13	3	1	1.00000			16
43	2		2.00000			17
21	3	1	1.00000			18
5	3	1	1.00000			19
29	2		2.00000			20
19	3		1.00000			21
45	1		1.00000			22
71	7		3.00000			23
30	1		1.00000			24
21	2		2.00000			25
45	1		1.00000			26
45	1		1.00000			27
105	3		3.00000			28
135	3		3.00000			29
135	8	1	4.00000			30
11	3		1.00000			31
32	2		2.00000			32
13	3	1	1.00000			33
49	4	1	2.00000			34
43	4	1	2.00000			35
11	3	1	1.00000			36
90	2		2.00000			37
21	2		2.00000			38
32	2		2.00000			39
105	3		3.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
13	4	1	1.00000			1
45	1		1.00000			2
170	3		3.00000			3
5	3	1	1.00000			4
30	1		1.00000			5
32	2		2.00000			6
18	2		2.00000			7
45	1		1.00000			8
45	1		1.00000			9
21	3	1	1.00000			10
45	1		1.00000			11
11	1		1.00000			12
34	4	1	2.00000			13
43	2		2.00000			14
60	2		2.00000			15
6	3	1	1.00000			16
90	2		2.00000			17
75	2		2.00000			18
11	1		1.00000			19
14	3	1	1.00000			20
43	2		2.00000			21
90	2		2.00000			22
45	1		1.00000			23
135	3		3.00000			24
29	2		2.00000			25
11	3	1	1.00000			26
45	1		1.00000			27
120	3		3.00000			28
30	1		1.00000			29
16	1		1.00000			30
105	3		3.00000			31
115	3		2.00000			32
135	3		2.00000			33
16	1		1.00000			34
79	5		3.00000			35
30	1		1.00000			36
150	2		2.00000			37
90	2		2.00000			38
20	4	1	2.00000			39
29	2		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
41	4		2.00000			1
16	1		1.00000			2
32	2		2.00000			3
90	2		2.00000			4
45	1		1.00000			5
90	2		2.00000			6
45	1		1.00000			7
23	2		2.00000			8
43	3		2.00000			9
195	4		4.00000			10
175	4		4.00000			11
120	3		3.00000			12
38	3	1	1.00000			13
135	3		3.00000			14
90	3		3.00000			15
90	2		2.00000			16
42	6	1	2.00000			17
31	4		2.00000			18
16	1		1.00000			19
45	1		1.00000			20
18	4		2.00000			21
60	2		2.00000			22
16	1		1.00000			23
6	3		1.00000			24
25	7		2.00000			25
11	1		1.00000			26
22	3		1.00000			27
45	1		1.00000			28
41	2		2.00000			29
25	2		2.00000			30
5	3	1	1.00000			31
16	1		1.00000			32
23	2		2.00000			33
11	1		1.00000			34
45	1		1.00000			35
30	1		1.00000			36
30	1		1.00000			37
45	1		1.00000			38
45	1		1.00000			39
30	1		1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
45	1		1.00000			1
90	3		3.00000			2
135	3		3.00000			3
195	3		3.00000			4
14	6	1	2.00000			5
50	2		2.00000			6
13	1		1.00000			7
61	2		2.00000			8
58	4		2.00000			9
57	5	1	3.00000			10
45	1		1.00000			11
22	4		2.00000			12
135	3		3.00000			13
41	4	1	2.00000			14
30	1		1.00000			15
30	1		1.00000			16
39	2		2.00000			17
135	3		3.00000			18
45	1		1.00000			19
13	1		1.00000			20
11	1		1.00000			21
16	1		1.00000			22
65	2		1.00000			23
32	2		2.00000			24
45	1		1.00000			25
45	1		1.00000			26
11	1		1.00000			27
32	2		2.00000			28
16	1		1.00000			29
25	6		2.00000			30
30	1		1.00000			31
16	4		2.00000			32
16	1		1.00000			33
19	3		1.00000			34
50	5		3.00000			35
23	3		2.00000			36
70	5		3.00000			37
30	1		1.00000			38
30	1		1.00000			39
90	2		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
45	1		1.00000			1
11	1		1.00000			2
32	2		2.00000			3
90	2		2.00000			4
32	2		2.00000			5
64	4		2.00000			6
11	3		1.00000			7
73	2		2.00000			8
11	3	1	1.00000			9
90	2		2.00000			10
73	4	1	2.00000			11
23	1		1.00000			12
27	4	1	2.00000			13
30	1		1.00000			14
90	2		2.00000			15
16	1		1.00000			16
90	2		2.00000			17
11	3	1	1.00000			18
11	3	1	1.00000			19
30	1		1.00000			20
19	3		1.00000			21
29	2		2.00000			22
12	3	1	1.00000			23
186	3		3.00000			24
180	4		4.00000			25
98	2		2.00000			26
375	5		5.00000			27
450	6		6.00000			28
565	4		4.00000			29
18	2		2.00000			30
40	2		3.00000			31
30	1		1.00000			32
180	4		2.00000			33
160	4		4.00000			34
135	3		3.00000			35
45	1		1.00000			36
13	3	1	1.00000			37
16	1		1.00000			38
45	1		1.00000			39
135	3		3.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
300	4		4.00000			1
60	2		2.00000			2
90	2		2.00000			3
27	2		2.00000			4
12	3		1.00000			5
135	3		3.00000			6
41	2		2.00000			7
161	3		3.00000			8
21	3	1	1.00000			9
5	3	1	1.00000			10
60	2		2.00000			11
30	1		1.00000			12
13	1		1.00000			13
90	2		2.00000			14
11	1		1.00000			15
45	1		1.00000			16
61	2		2.00000			17
16	1		1.00000			18
15	3	1	1.00000			19
60	2		2.00000			20
32	2		2.00000			21
49	4		2.00000			22
19	6		2.00000			23
30	1		1.00000			24
11	1		1.00000			25
60	2		2.00000			26
25	3		3.00000			27
19	1		1.00000			28
40	4	1	2.00000			29
13	1		1.00000			30
25	2		2.00000			31
150	2		2.00000			32
51	4	1	2.00000			33
105	3		2.00000			34
11	3	1	1.00000			35
225	3		3.00000			36
75	2		2.00000			37
105	3		3.00000			38
22	6		1.00000			39
17	2		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
45	1		1.00000			1
90	2		2.00000			2
21	3	1	1.00000			3
120	3		3.00000			4
13	1		1.00000			5
135	3		3.00000			6
90	3		3.00000			7
27	2		2.00000			8
13	1		1.00000			9
225	3		3.00000			10
49	4		2.00000			11
21	3	1	1.00000			12
90	2		2.00000			13
90	2		2.00000			14
150	2		2.00000			15
13	1		1.00000			16
121	4		4.00000			17
16	1		1.00000			18
90	2		2.00000			19
90	2		2.00000			20
24	4	2	2.00000			21
30	1		1.00000			22
61	2		2.00000			23
32	2		2.00000			24
23	4		2.00000			25
29	2		2.00000			26
10	3	1	1.00000			27
105	3		3.00000			28
120	3		3.00000			29
6	3	1	1.00000			30
30	1		1.00000			31
29	2		2.00000			32
17	6		2.00000			33
90	2		4.00000			34
30	1		1.00000			35
60	2		2.00000			36
90	2		2.00000			37
150	2	1	2.00000			38
21	3	1	1.00000			39
60	2		2.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	3		1.00000			1
11	1		1.00000			2
16	1		1.00000			3
8	1		1.00000			4
50	2		2.00000			5
90	2		2.00000			6
30	1		1.00000			7
24	4		2.00000			8
135	3		3.00000			9
30	1		1.00000			10
105	3		3.00000			11
29	2		2.00000			12
105	3		3.00000			13
44	4	1	2.00000			14
30	1		1.00000			15
105	3		3.00000			16
27	2		2.00000			17
19	3	1	1.00000			18
13	3	1	1.00000			19
30	1		1.00000			20
11	3	1	1.00000			21
14	3	1	1.00000			22
14	1		1.00000			23
30	1		1.00000			24
13	1		1.00000			25
120	3		3.00000			26
23	3		1.00000			27
135	3		3.00000			28
60	2		2.00000			29
135	3		3.00000			30
13	1		1.00000			31
120	3		3.00000			32
11	1		1.00000			33
27	2		2.00000			34
1	1		1.00000			35
2	3		1.00000			36
9	3	1	1.00000			37
7	1		1.00000			38
9	3	1	1.00000			39
6	3		1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
5	3		1.00000			1
9	1		1.00000			2
5	1		1.00000			3
9	2		2.00000			4
5	1		1.00000			5
3	6		1.00000			6
6	6	1	1.00000			7
1	3		1.00000			8
2	3	1	1.00000			9
6	3	1	1.00000			10
9	3		1.00000			11
6	3	1	1.00000			12
3	3		1.00000			13
7	6	1	2.00000			14
5	3	1	1.00000			15
3	3		1.00000			16
2	1		1.00000			17
5	1		1.00000			18
8	1		1.00000			19
6	3	1	1.00000			20
9	3		1.00000			21
3	3	1	1.00000			22
6	3		1.00000			23
3	3	1	1.00000			24
6	3	1	1.00000			25
5	3		1.00000			26
5	1		1.00000			27
6	3		1.00000			28
6	3		1.00000			29
5	1		1.00000			30
3	6	1	1.00000			31
2	3		1.00000			32
4	3	1	1.00000			33
9	6		1.00000			34
6	3	1	1.00000			35
3	3	1	1.00000			36
7	1		1.00000			37
2	3	1	1.00000			38
6	1		1.00000			39
9	3	1	1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	3	1	1.00000			1
6	3	1	1.00000			2
2	3	1	1.00000			3
5	3		1.00000			4
2	3	1	1.00000			5
5	1		1.00000			6
9	3		1.00000			7
2	3	1	1.00000			8
8	6	1	1.00000			9
2	3		1.00000			10
9	3	1	1.00000			11
9	3		1.00000			12
3	3		1.00000			13
9	3	1	1.00000			14
5	3	1	1.00000			15
5	1		1.00000			16
3	1		1.00000			17
5	1		1.00000			18
9	1		1.00000			19
6	3		1.00000			20
7	3	1	1.00000			21
8	6	1	1.00000			22
7	1		1.00000			23
1	3	1	1.00000			24
4	1		1.00000			25
4	1		1.00000			26
3	3		1.00000			27
5	1		1.00000			28
2	3	1	1.00000			29
6	3		1.00000			30
5	3		1.00000			31
6	3	1	1.00000			32
7	1		1.00000			33
7	2		2.00000			34
2	3		1.00000			35
3	3		1.00000			36
5	3		1.00000			37
6	6		1.00000			38
4	1		1.00000			39
6	3	1	1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
5	3	1	1.00000			1
9	1		1.00000			2
5	1		1.00000			3
3	3	1	1.00000			4
5	3		1.00000			5
6	3	1	1.00000			6
6	3	1	1.00000			7
2	3		1.00000			8
3	3		1.00000			9
3	3	1	1.00000			10
8	3	1	1.00000			11
3	3		1.00000			12
4	1		1.00000			13
3	1		1.00000			14
	1		1.00000			15
6	1		1.00000			16
1	1		1.00000			17
9	1		1.00000			18
6	3	1	1.00000			19
5	1		1.00000			20
5	1		1.00000			21
8	3	1	1.00000			22
9	3	1	1.00000			23
4	1		1.00000			24
3	3	1	1.00000			25
5	1		1.00000			26
4	1		1.00000			27
9	3	1	1.00000			28
5	1		1.00000			29
5	3		1.00000			30
2	3	1	1.00000			31
10	3	1	1.00000			32
5	1		1.00000			33
3	3		1.00000			34
5	1		1.00000			35
3	3	1	1.00000			36
2	3		1.00000			37
9	3	1	1.00000			38
4	3		1.00000			39
4	1		1.00000			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	3	1	1.00000			1
3	1	1	2.00000			2
9	3	1	1.00000			3
9	3	1	1.00000			4
5	1	1	1.00000			5
-58						6
98658	2094	209				7
						8
						9
675	331	53				10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

Schedule Page: 426.3 Line No.: 29 Column: e
2.4 and 7.2

Schedule Page: 426.3 Line No.: 35 Column: e
2.4 and 7.2

Schedule Page: 426.4 Line No.: 27 Column: e
2.4 and 7.2

Schedule Page: 426.5 Line No.: 17 Column: e
2.4 and 7.2

Schedule Page: 426.8 Line No.: 17 Column: e
2.4 and 7.2

Schedule Page: 426.9 Line No.: 9 Column: e
2.4 and 7.2

Schedule Page: 426.9 Line No.: 25 Column: e
2.4 and 7.2

Schedule Page: 426.10 Line No.: 22 Column: c
60 or 115

Schedule Page: 426.12 Line No.: 20 Column: c
70 or 115

Schedule Page: 426.13 Line No.: 2 Column: e
2.4 and 7.2

Schedule Page: 426.13 Line No.: 17 Column: e
2.4 and 7.2

Schedule Page: 426.16 Line No.: 11 Column: e
2.4 and 7.2

Schedule Page: 426.21 Line No.: 6 Column: a
The original entries in column f were in two decimal places, which the FERC software rounds automatically to whole numbers. The entry here is an adjustment to present the correct total.

Schedule Page: 426.21 Line No.: 8 Column: a
Substation voltage classes are listed separately for each substation. Therefore, there will be multiple line entries for substations having more than one voltage class. Substations having combined total capacity of ≥ 10 MVA are listed individually. Substations with less than 10 MVA capacity are lumped together in one line item. All transmission substations are ≥ 10 MVA.

There are 92 Transmission Substations and 605 Distribution Substations. This represents a total of 697 physical transmission and distribution substations ($92+605=697$). All transmission and distribution substations are unattended.

Any substation that has a transmission-to-transmission transformation (Primary voltage ≥ 60 kV and secondary voltage ≥ 60 kV) is defined as a transmission station, regardless of the number of distribution assets in the station. Hence, substations with both transmission and distribution (secondary voltage < 60 kV) transformers are characterized as Transmission in the list. There are 59 Transmission Substations with both transmission and distribution transformers; one of them < 10 MVA. There are 664 substations

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

with distribution transformer banks. (605+59 = 664)

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		PG&E Corporation		
3				
4	Corporate A&G Allocations		923.0, 426.5	105,180,139
5	Total - Administrative & General Expenses			105,180,139
6				
7		Eureka Energy Company		
8	Rent Expense		532.0	321,288
9				
10	Total Non-power Goods/Srv.provided by Affiliates			105,501,427
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21		PG&E Corporation	930.2	
22	ACCOUNTING			542,720
23	ADMINISTRATION			87,601
24	AFFILIATE RULES COMPLIANCE SUPPORT			24,561
25	BANKING SERVICES			34,380
26	EMPLOYEE TRANSFER FEE			105,609
27	BUSINESS PLANNING SERVICES			26,747
28	COMPLIANCE & ETHICS SUPPORT			8,194
29	CONSULTING SERVICES			5,722
30	CORPORATE SECRETARY SUPPORT			1,780
31	CORPORATE SUSTAINABILITY SUPPORT			248,154
32	FINANCIAL FORECASTING AND ANALYSIS			57,603
33	FLEET SERVICES			373
34	HUMAN RESOURCES SUPPORT			219,472
35	INFORMATION TECHNOLOGY			361,552
36	INSURANCE SUPPORT			9,284
37	INTERNAL AUDIT SERVICES			6,071
38	INVESTOR RELATIONS SUPPORT			9,917
39	LEGAL			45,113
40	MISC EXPENSE			621
41	REAL ESTATE AND FACILITY			102,714
42	SECURITY SUPPORT			932,812
1	Non-power Goods or Services Provided by Affiliated			
2				

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				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22	SOURCING SUPPORT			123,984
23	STRATEGIC ANALYSIS SUPPORT			48,014
24	TAX SERVICES			64,684
25	INTEREST			394,718
26				
27				
28	Total - A&G Direct Charges to PG&E Corp			3,462,400
29				
30		FUELCO	930.2	
31	ACCOUNTING			18,231
32	CFO SUPPORT			6,077
33	FUEL PURCHASING SUPPORT			483,151
34	LEGAL			2,024
35	SUPPLY CHAIN SUPPORT			9,151
36				
37	Total - A&G Direct Charges to FUELCO			518,634
38				
39				
40				
41	TOTAL NON-POWER GOODS/SRV PROVIDED FOR			3,981,034
42				

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2021	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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Note

The 2020 Corporation's A&G Allocation Rate is calculated below and will be rounded up to 99% (Three-Factor Methodology and Headcount).

1. Three-Factor Methodology – 99.99%

It is the simple average of the following three ratios:

- a. Affiliate Assets/Total Consolidated Assets
- b. Affiliate Operating Expenses less Fuel purchase costs /Total Consolidated Operating Expenses less Fuel purchase costs
- c. Affiliate Headcount/Total Consolidate Headcount

2. Capitalization: 100%

It is the ratio of affiliate's capitalization over total consolidated capitalization.

3. Headcount: 99.9%

It is the ratio of affiliate's headcount over total headcount for all entities.

All Corporation's cost centers allocate its charges based on Three Factor Methodology, except for the following cost centers.

COST CENTER	Description	Allocation Approach
PCC 20036	HOLD-Banking & Money Management	Capitalization
PCC 20039	HOLD-Investments & Benefits	Headcount
PCC 20041	HOLD- Investor Relations	Capitalization
PCC 20050	HOLD – Senior VP Human Resource	Headcount

SELECTED FINANCIAL DATA - CLASS A, B, C, AND D ELECTRIC UTILITIES
PACIFIC GAS AND ELECTRIC COMPANY
PERSON RESPONSIBLE FOR THIS REPORT: David Thomason, Vice President, CFO and Controller
(PREPARED FROM INFORMATION IN THE 2020 FERC ANNUAL REPORTS)

	December 31		Annual Average
	2019	2020	
NET ELECTRIC PLANT INVESTMENT (a)			
Electric Utility Plant (California Only)			
1. Intangible Plant	\$ 1,180,995,855	\$ 1,155,424,681	\$ 1,168,210,268
2. Land and Land Rights	624,175,634	650,790,964	637,483,299
3. Depreciable Plant	67,239,111,217	71,704,526,946	69,471,819,082
4. Nuclear Fuel	3,099,071,385	3,219,553,706	3,159,312,546
5. Gross Electric Utility Plant	72,143,354,091	76,730,296,297	74,436,825,195
6. Electric Plant Held for Future Use - Net	0	0	0
7. Construction Work in Progress - Electric	2,278,121,533	2,211,726,113	2,244,923,823
8. Accumulated Deferred Income Taxes	7,445,591,597	7,019,341,739	7,232,466,668
9. Less: Reserves for Depreciation - Electric Utility Plant	29,566,029,119	31,210,612,711	30,388,320,915
10. Less: Amortization and Depletion Reserves	3,471,973,667	3,390,798,359	3,431,386,013
11. Less: Customer Advances and Contribution in Aid of Construction	229,861,025	211,023,299	220,442,162
12. Less: Accumulated Deferred Income and Investment Tax Credits	6,953,898,868	7,486,751,242	7,220,325,055
13. Material and Supplies - Electric Only	356,607,340	346,383,429	351,495,385
14. Net Electric Plant Investment	<u>\$ 42,001,911,882</u>	<u>\$ 44,008,561,966</u>	<u>\$ 43,005,236,926</u>
CAPITALIZATION (Total Company)			
15. Common Stock	\$ 1,321,874,045	\$ 1,321,874,045	\$ 1,321,874,045
16. Capital Stock (Premium, Discount and Expense)-Net	1,769,325,445	1,769,325,445	1,769,325,445
17. Other Paid in Capital	6,780,547,928	26,516,580,090	16,648,564,009
18. Retained Earnings	(4,794,324,809)	(4,389,005,328)	(4,591,665,069)
19. Other Miscellaneous Capital Accounts	0	0	0
20. Common Stock and Equity (Lines 15 through 19)	5,077,422,609	25,218,774,252	15,148,098,430
21. Preferred Stock	257,994,575	257,994,575	257,994,575
22. Long-Term Debt	19,887,100,000	31,832,344,699	25,859,722,350
23. Notes Payable and Current Portion of Long-Term Debt	3,138,570,758	3,555,000,000	3,346,785,379
24. Total Capitalization (Lines 20 through 23)	<u>\$ 28,361,087,942</u>	<u>\$ 60,864,113,526</u>	<u>\$ 44,612,600,734</u>

(a) Includes Common Plant Allocations.

PACIFIC GAS AND ELECTRIC COMPANY
INCOME STATEMENT DATA
FOR CALIFORNIA INTRASTATE ELECTRIC OPERATIONS ONLY (b)

	Annual Amount
25. Operating Revenues	13,890,072,200
26. Operating and Maintenance Expense	11,022,381,199
27. Depreciation	2,165,415,394
28. Depreciation for Asset Retirement Costs	-
29. Amortization and Depletion Expenses and Property Losses	208,716,079
30. Regulatory Debits	10,608,342
31. Regulatory Credits	(892,660,285)
32. Property Taxes (Ad Valorem)	312,151,635
33. Taxes Other than Income and Property Taxes	125,843,078
34. Operating Revenue Deductions (Before Federal and California Income Taxes)	12,952,455,442
35. Federal and California Income Taxes - Net	333,095,449
36. Gains and Losses from Disposition of Electric Plant - Net	(145,599)
37. Accretion Expense	-
38. Total Utility Operating Expenses	13,285,405,292
39. Net Operating Income (California Intrastate Electric Operations Only)	604,666,908
OTHER INCOME AND EXPENSE (Total Company)	
40. Net Operating Income from Other Utility Operations (Total)	717,900,065
41. Net Other Income and Deductions	200,014,197
42. Income Before Interest Charges	1,522,581,170
43. Interest Charges	1,111,622,682
44. Income Before Extraordinary Items	410,958,488
45. Extraordinary Items - Net of Income Tax	-
46. Net Income	410,958,488
47. Preferred Stock Dividends and Redemption Premium	-
48. Income Available for Common Stock	\$ 410,958,488
49. Common Stock Dividends	-
OTHER DATA (CALIFORNIA INTRASTATE ELECTRIC OPERATIONS ONLY) (b) Items (48-50)	
50. Payroll Charged to Operating and Maintenance Expense	\$ 1,391,522,211
51. Payroll Capitalized to Utility Plant - Electric	985,270,819
52. Total Payroll	\$ 2,376,793,030
53. Purchased Power	\$ 4,613,389,452
54. Allowance for Funds Used During Construction	\$ 140,607,684
55. Interdepartmental Revenues	\$ 51,081,618
56. Interdepartmental Expenses	\$ 72,093,081
57. Revenue from Sales to Residential Customers	\$ 5,522,669,106
58. Residential Sales in Kwhs	29,814,086,000
59. Total Revenue Sales to Ultimate Customers	\$ 13,366,378,507
60. Kwhs Sold to Ultimate Customers	78,792,915,000
61. Average Number of Residential Customers	4,910,767
62. Average Number of Ultimate Customers	5,590,562

(b) Assumes CPUC Jurisdictional Portion of Electric Operations.