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

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

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

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

| **Exact Legal Name of Respondent (Company)** | **Year/Period of Report** |
|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | **End of** 2020/Q4 |

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

## GENERAL INFORMATION

### I. Purpose

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

### II. Who Must Submit

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

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

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

### III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

**IV. When to Submit:**

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

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

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

## V. Where to Send Comments on Public Reporting Burden.

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

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

## GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

## EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

**General Penalties**

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

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

**IDENTIFICATION**

| 01 Exact Legal Name of Respondent | 02 Year/Period of Report |
|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | End of 2020/Q4 |

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
77 BEALE STREET, P.O BOX 770000, SAN FRANCISCO, CA 94177

| 05 Name of Contact Person | 06 Title of Contact Person |
|---|---|
| JENNIFER GARBODEN | 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* | 09 This Report Is | 10 Date of Report *(Mo, Da, Yr)* |
|---|---|---|
| (415) 973-5456 | (1) [X] An Original (2) [ ] A Resubmission | 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 | 03 Signature | 04 Date Signed *(Mo, Da, Yr)* |
|---|---|---|
| DAVID THOMASON | DAVID THOMASON | 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## LIST OF SCHEDULES (Electric Utility)

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

LIST OF SCHEDULES (Electric Utility) (continued)

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

## GENERAL INFORMATION

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

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) [X] No

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONTROL OVER RESPONDENT

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

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CORPORATIONS CONTROLLED BY RESPONDENT

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

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

| Line No. | Name of Company Controlled (a) | Kind of Business (b) | Percent Voting Stock Owned (c) | Footnote Ref. (d) |
|---|---|---|---|---|
| 1 | 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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
| --- | --- | --- | --- |
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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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 | | | | |
| 9 | | | | |
| 10 | | | | |
| 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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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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 | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
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| 27 | | | | |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

| Line No. | Title (a) | Name of Officer (b) | Salary for Year (c) |
|---|---|---|---|
| 1 | 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, | David S. Thomason | 339,479 |
| 5 | Pacific Gas and Electric Company | | |
| 6 | Chief Executive Officer and President, Pacific Gas and | Andrew M. Vesey | 587,310 |
| 7 | Electric Company | | |
| 8 | Senior Vice President and General Counsel, Pacific | Janet C. Loduca | 380,096 |
| 9 | Gas and Electric Company | | |
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***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

| Line No. | Name (and Title) of Director<br>(a) | Principal Business Address<br>(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 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

| Line No. | Name (and Title) of Director (a) | Principal Business Address (b) |
|---|---|---|
| 1 | 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 |
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| 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 |
| 48 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

| Line No. | Name (and Title) of Director (a) | Principal Business Address (b) |
|---|---|---|
| 1 | 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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**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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

| Line No. | FERC Rate Schedule or Tariff Number | FERC Proceeding |
|---|---|---|
| 1 | 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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

[X] Yes
[ ] No

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

| Line No. | Accession No. | Document Date \ Filed Date | Docket No. | Description | Formula Rate FERC Rate Schedule Number or Tariff Number |
|---|---|---|---|---|---|
| 1 | 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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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

| Line No. | Page No(s). | Schedule | Column | Line No |
|---|---|---|---|---|
| 1 | | NOT APPLICABLE | | |
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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.

**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 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.

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 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% |

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, 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

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

- 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

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
- Wondy 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.

**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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | **UTILITY PLANT** | | | |
| 2 | Utility Plant (101-106, 114) | 200-201 | 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<br>(a) | Ref. Page No.<br>(b) | Current Year End of Quarter/Year Balance<br>(c) | Prior Year End Balance 12/31<br>(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 |

# 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | Total Current Year to Date Balance for Quarter/Year (c) | Total Prior Year to Date Balance for Quarter/Year (d) | Current 3 Months Ended Quarterly Only No 4th Quarter (e) | Prior 3 Months Ended Quarterly Only No 4th Quarter (f) |
|---|---|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | | | |
| 2 | Operating Revenues (400) | 300-301 | 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 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

| ELECTRIC UTILITY | | GAS UTILITY | | OTHER UTILITY | | |
|---|---|---|---|---|---|---|
| Current Year to Date (in dollars) (g) | Previous Year to Date (in dollars) (h) | Current Year to Date (in dollars) (i) | Previous Year to Date (in dollars) (j) | Current Year to Date (in dollars) (k) | Previous Year to Date (in dollars) (l) | Line No. |
| | | | | | | 1 |
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account<br>(a) | (Ref.) Page No.<br>(b) | TOTAL Current Year<br>(c) | TOTAL Previous Year<br>(d) | Current 3 Months Ended Quarterly Only No 4th Quarter<br>(e) | Prior 3 Months Ended Quarterly Only No 4th Quarter<br>(f) |
|---|---|---|---|---|---|---|
| 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 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | | | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | | | | |
| 33 | Revenues From Nonutility Operations (417) | | 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 | | |

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

***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 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| 41 | 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) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(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) | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(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 |

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

This consists of the following:

| | 2020 | 2019 |
|---|---|---|
| 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:

| | 2020 | 2019 |
|---|---|---|
| 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:

| | 2020 | 2019 |
|---|---|---|
| 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) |

**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:

| | 2020 | 2019 |
|---|---|---|
| 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 | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

**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.

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)

| Line no. | Name of Energy Storage Project | Functional classification | Location of the Project | Project Cost | Operations (Excluding Fuel used in Storage | Maintenance | Cost of fuel used in storage operations | Account No. 555.1, Power Purchased | Other Expenses |
|---|---|---|---|---|---|---|---|---|---|

| | | | | | Operations) | | | for Storage Operations | |
|---|---|---|---|---|---|---|---|---|---|
| 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

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.

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;

- 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 Kincade 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.

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.

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).

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.

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 |
|---|---|---|---|---|---|---|---|---|---|
| Financing debt | $ 22,450 | $ 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) | — | — | — |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 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);

- claims arising out of or based on the 2019 Kincade 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.

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:

| | Year Ended December 31, 2020 | | |
|---|---|---|---|
| **(in millions)** | **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:

| | Petition Date Through December 31, 2019 | | |
|---|---|---|---|
| **(in millions)** | **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.

## 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***

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:

| | Year Ended | |
|---|---|---|
| **(in millions)** | **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** |

| | | |
|---|---|---|
| **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**

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**

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**

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***

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.

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 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| 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**

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:

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

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.

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***

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:

| | Balance at December 31, | | Recovery Period |
|---|---|---|---|
| **(in millions)** | **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** | |

(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,**

| **(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:

| | **Receivable Balance at December 31,** | |
|---|---|---|
| **(in millions)** | **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 | | |

| | | |
|---|---|---|
| | 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** |

| | **Payable Balance at December 31,** | |
|---|---|---|
| **(in millions)** | **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**

**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 |
|---|---|---|---|---|---|
| Utility revolving credit facility | July 2023 | $ 3,500 (1) | $ 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.

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.

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.

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.

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***

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.

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.

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 December 31, 2020 | Balance at December 31, 2019 | Treatment under Plan on the Effective Date (1) |
|---|---|---|---|---|
| **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) |

| | | | | |
|---|---|---|---|---|
| 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) |
| **Other borrowings:** | | | | |
| Term Loan - Stated Maturity: 2019 | variable rate (9) | — | 250 | Exchanged (18) |
| **Total Borrowings under Pre-Petition Credit Facility** | | **—** | **3,138** | |
| **Total Utility Pre-Petition Debt** | | **—** | **21,526** | |
| **Total PG&E Corporation Consolidated Pre-Petition Debt** | | **$ —** | **$ 22,176** | |
| | | | | |
| **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 | — | |

| | | | |
|---|---|---|---|
| 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%.

(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 % |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 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").

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.

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**

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.

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 |

| | | | |
|---|---|---|---|
| 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 | — | — | | — |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 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.

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.

**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.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **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.

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:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| **(in millions)** | **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:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **(in millions)** | **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 | — |

| | | | | |
|---|---|---|---|---|
| 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.

(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:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **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:

| (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.

## 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:

| | | Contract Volume At December 31, | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **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.

(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:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| 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:

| | Commodity Risk | | | |
|---|---|---|---|---|
| **(in millions)** | **Gross Derivative Balance** | **Netting** | **Cash Collateral** | **Total Derivative Balance** |
| 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**

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.

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2020 | | | | |
| **(in millions)** | **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** |

| | | | | | |
|---|---|---|---|---|---|
| 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** |

| | | | | | |
|---|---|---|---|---|---|
| **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.

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.

| (in millions) | Fair Value at At December 31, 2020 | | Valuation Technique | Unobservable Input | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | | | **Range (1)/Weighted-Average Price (2)** |
| 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 At December 31, 2019 | | Valuation Technique | Unobservable Input | |
|---|---|---|---|---|---|
| **Fair Value Measurement** | **Assets** | **Liabilities** | | | **Range (1)/Weighted-Average Price (2)** |
| 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:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions)** | **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** |

(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):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| (in millions) | 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** | | | | |

| 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.

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.

(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.

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.

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.

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 %** |

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.

| | Fair Value Measurements At December 31, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2020 | | | | 2019 | | | |
| **(in millions)** | **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.

**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.

**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** | **Fixed-Income** |
|---|---|
| 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** | **Fixed-Income** |
|---|---|
| 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***

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**

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:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **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**

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.

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.

***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**

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."

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.

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.

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 Kincade 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 Kincade 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

- 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.

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.

***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 Kincade 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.

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 Kincade 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).

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.

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**

***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***

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).

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***

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***

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.

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.

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.

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.

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.

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.

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.

***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**

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 | Balance at 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.

***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***

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.

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:

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

| | | | | | | |
|---|---|---|---|---|---|---|
| 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.

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**

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.

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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Item (a) | Unrealized Gains and Losses on Available-for-Sale Securities (b) | Minimum Pension Liability adjustment (net amount) (c) | Foreign Currency Hedges (d) | Other Adjustments (e) |
|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | | | | ( 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) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

| Line No. | Other Cash Flow Hedges Interest Rate Swaps (f) | Other Cash Flow Hedges [Specify] (g) | Totals for each category of items recorded in Account 219 (h) | Net Income (Carried Forward from Page 117, Line 78) (i) | Total Comprehensive Income (j) |
|---|---|---|---|---|---|
| 1 | | | ( 986,708) | [redacted] | |
| 2 | | | 597,861 | | |
| 3 | | | 1,406,636 | | |
| 4 | | | 2,004,497 | ( 7,621,767,673) | ( 7,619,763,176) |
| 5 | | | 1,017,789 | [redacted] | |
| 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) | [redacted] | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

| Line No. | Classification (a) | Total Company for the Current Year/Quarter Ended (b) | Electric (c) |
|---|---|---|---|
| 1 | Utility Plant | | |
| 2 | In Service | | |
| 3 | Plant in Service (Classified) | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

| Gas (d) | Other (Specify) (e) | Other (Specify) (f) | Other (Specify) (g) | Common (h) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

| Line No. | Description of item<br>(a) | Balance Beginning of Year<br>(b) | Changes during Year<br>Additions<br>(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 | Line |
|---|---|---|---|
| Amortization (d) | Other Reductions (Explain in a footnote) (e) | End of Year (f) | No. |
| | | | 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 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Additions (c) |
|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | |
| 2 | (301) Organization | | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

| Line No. | Account<br>(a) | Balance Beginning of Year<br>(b) | Additions<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

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

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

| Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| 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)

| 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 |
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| | | | | | 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 |

***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***

Netgative 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC PLANT LEASED TO OTHERS (Account 104)

| Line No. | Name of Lessee (Designate associated companies with a double asterisk) (a) | Description of Property Leased (b) | Commission Authorization (c) | Expiration Date of Lease (d) | Balance at End of Year (e) |
|---|---|---|---|---|---|
| 1 | None | | | | |
| 2 | | | | | |
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| 46 | | | | | |
| 47 | TOTAL | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

| Line No. | Description and Location Of Property (a) | Date Originally Included in This Account (b) | Date Expected to be used in Utility Service (c) | Balance at End of Year (d) |
|---|---|---|---|---|
| 1 | Land and Rights: | | | |
| 2 | None | | | |
| 3 | | | | |
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| 17 | | | | |
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| 19 | | | | |
| 20 | | | | |
| 21 | Other Property: | | | |
| 22 | None | | | |
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| 27 | | | | |
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| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | Total | | | 0 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project<br>(a) | Construction work in progress - Electric (Account 107)<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 TEMBLOR-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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 RECONDUC | 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 DeSabla 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 Transfrmr 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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 PANOCHE-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 DeSabla-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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project<br>(a) | Construction work in progress - Electric (Account 107)<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | 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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| 40 | | |
| 41 | | |
| 42 | | |
| 43 | TOTAL | 1,929,075,179 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

**Section A. Balances and Changes During Year**

| Line No. | Item (a) | Total (c+d+e) (b) | Electric Plant in Service (c) | Electric Plant Held for Future Use (d) | Electric Plant Leased to Others (e) |
|---|---|---|---|---|---|
| 1 | Balance Beginning of Year | 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 | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) X An Original<br>(2) __ A Resubmission | 04/13/2021 | 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) | 414,201,553 |
| 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 | (580,080) |
| | 84,103,975 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

| Line No. | Description of Investment (a) | Date Acquired (b) | Date Of Maturity (c) | Amount of Investment at Beginning of Year (d) |
|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

| Line No. | Description of Investment (a) | Date Acquired (b) | Date Of Maturity (c) | Amount of Investment at Beginning of Year (d) |
|---|---|---|---|---|
| 1 | PG&E AR Facility LLC | | | |
| 2 | Additional Paid in Capital | 2020 | | |
| 3 | Undistributed Earnings | | | |
| 4 | | | | |
| 5 | SUBTOTAL | | | |
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| 40 | | | | |
| 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 form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

| Equity in Subsidiary Earnings of Year (e) | Revenues for Year (f) | Amount of Investment at End of Year (g) | Gain or Loss from Investment Disposed of (h) | Line No. |
|---|---|---|---|---|
| | | | | 1 |
| | | 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 form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

| Equity in Subsidiary Earnings of Year (e) | Revenues for Year (f) | Amount of Investment at End of Year (g) | Gain or Loss from Investment Disposed of (h) | Line No. |
|---|---|---|---|---|
| | | | | 1 |
| | | 50,000,000 | | 2 |
| 29,092,293 | | 29,092,293 | | 3 |
| | | | | 4 |
| 29,092,293 | | 79,092,293 | | 5 |
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| | | | | 39 |
| | | | | 40 |
| | | | | 41 |
| 29,086,864 | | 134,313,797 | | 42 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## MATERIALS AND SUPPLIES

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Balance End of Year (c) | Department or Departments which Use Material (d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

Allowances (Accounts 158.1 and 158.2)

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

| Line No. | SO2 Allowances Inventory (Account 158.1) (a) | Current Year No. (b) | Current Year Amt. (c) | 2021 No. (d) | 2021 Amt. (e) |
|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | 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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

Allowances (Accounts 158.1 and 158.2) (Continued)

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

| 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 |
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| | | | | | | | | 19 |
| | | | | | | 3.00 | | 20 |
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| | | | | | | | | 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 |

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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

Allowances (Accounts 158.1 and 158.2)

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

| Line No. | NOx Allowances Inventory (Account 158.1) (a) | Current Year No. (b) | Current Year Amt. (c) | 2021 No. (d) | 2021 Amt. (e) |
|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | | | | |
| 2 | | | | | |
| 3 | Acquired During Year: | | | | |
| 4 | Issued (Less Withheld Allow) | | | | |
| 5 | Returned by EPA | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | Purchases/Transfers: | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | Total | | | | |
| 16 | | | | | |
| 17 | Relinquished During Year: | | | | |
| 18 | Charges to Account 509 | | | | |
| 19 | Other: | | | | |
| 20 | | | | | |
| 21 | Cost of Sales/Transfers: | | | | |
| 22 | | | | | |
| 23 | | | | | |
| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
| 28 | Total | | | | |
| 29 | Balance-End of Year | | | | |
| 30 | | | | | |
| 31 | Sales: | | | | |
| 32 | Net Sales Proceeds(Assoc. Co.) | | | | |
| 33 | Net Sales Proceeds (Other) | | | | |
| 34 | Gains | | | | |
| 35 | Losses | | | | |
| | Allowances Withheld (Acct 158.2) | | | | |
| 36 | Balance-Beginning of Year | | | | |
| 37 | Add: Withheld by EPA | | | | |
| 38 | Deduct: Returned by EPA | | | | |
| 39 | Cost of Sales | | | | |
| 40 | Balance-End of Year | | | | |
| 41 | | | | | |
| 42 | Sales: | | | | |
| 43 | Net Sales Proceeds (Assoc. Co.) | | | | |
| 44 | Net Sales Proceeds (Other) | | | | |
| 45 | Gains | | | | |
| 46 | Losses | | | | |

Allowances (Accounts 158.1 and 158.2) (Continued)

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

| 2022 | | 2023 | | Future Years | | Totals | | Line |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | No. |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

| Line No. | Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a) | Total Amount of Loss (b) | Losses Recognised During Year (c) | WRITTEN OFF DURING YEAR Account Charged (d) | WRITTEN OFF DURING YEAR Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | None | | | | | |
| 2 | | | | | | |
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| 18 | | | | | | |
| 19 | | | | | | |
| 20 | TOTAL | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

| Line No. | Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a) | Total Amount of Charges (b) | Costs Recognised During Year (c) | WRITTEN OFF DURING YEAR Account Charged (d) | WRITTEN OFF DURING YEAR Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 21 | 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 |

***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<br>November 2020 (1/1/2020 to 12/31/2020) | 71,099 | 71,099 | - | 0 | 0 |
| Soledad 115/60 kV Transformer Capacity<br>November 2020 (1/1/2020 to 12/31/2020) | 46,362 | 46,362 | - | 0 | 0 |
| Napa - Tulucay No. 1 60 kV Line Upgrades<br>November 2020 (1/1/2020 to 12/31/2020) | 39,983 | 39,983 | - | 0 | 0 |
| Clear Lake 60 kV System Reinforcement<br>November 2020 (1/1/2020 to 12/31/2020) | 35,304 | 35,304 | - | 0 | 0 |
| Taft 115/70 kV Transformer #2 Replacement<br>November 2020 (1/1/2020 to 12/31/2020) | 32,372 | 32,372 | - | 0 | 0 |
| Monta Vista - Los Gatos - Evergreen 60 kV Project<br>November 2020 (1/1/2020 to 12/31/2020) | 31,157 | 31,157 | - | 0 | 0 |
| Cressey - North Merced 115 kV Line Addition<br>November 2020 (1/1/2020 to 12/31/2020) | 27,777 | 27,777 | - | 0 | 0 |
| Tesla - Newark<br>November 2020 (1/1/2020 to 12/31/2020) | 288,461 | 288,461 | - | 0 | 0 |
| ALMADEN (LOS GATOS) 60KV SHUNT CAPACITOR<br>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 |

FOOTNOTE DATA

| | | | | | |
|---|---|---|---|---|---|
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Ashlan - Gregg and Ashlan - Herndon 230 kV Line Reconductor | 724,676 | 724,676 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Evergreen - Mabury 60 to 115 kV Conversion | 1,606,258 | 1,606,258 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Rio Oso - Atlantic 230 kV Line Project | 824,979 | 824,979 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Watsonville Voltage Conversion | 2,341,382 | 2,341,382 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Reedley-Dinuba | 436,885 | 436,885 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| Reedley-Orosi | 304,604 | 304,604 | - | 0 | 0 |
| November 2020 (1/1/2020 to 12/31/2020) | | | | | |
| DCPP License Renewal Cost | 12,302,620 | 2,050,436 | - | 0 | 10,252,184 |
| January 1, 2018 (01-2018 to 12-2025) | | | | | |
| DCPP Canceled Projects | 51,295,864 | 9,752,837 | - | 0 | 41,543,026 |
| January 1, 2018 (01-2020 to 12-2025) | | | | | |
| 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 | | | | | |
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| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | (see details in footnotes) | 2,177,288 | 186 | ( 2,276,866) | 186 |
| 23 | | | | | |
| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
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| 38 | | | | | |
| 39 | | | | | |
| 40 | | | | | |

**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) | |

| | | | | |
|---|---|---|---|---|
| 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 | | |

| | | | | |
|---|---|---|---|---|
| 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) | |

| | | | | |
|---|---|---|---|---|
| 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 | This Report is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) X An Original<br>(2) __ A Resubmission | (Mo, Da, Yr)<br>04/13/2021 | 2020/Q4 |

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) | |

| | | | | |
|---|---|---|---|---|
| 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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|---|---|---|---|---|
| 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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|---|---|---|---|---|
| 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:Soltage,LLC-BradleyGillettSolar1 | (2,016) | | | (2,016) |
| R21-DS-BASSLAKEJOINTELESchApp55332RESBCT | (5,338) | 5,338 | | |
| R21DIS:CityofMaderaRES-BCT (App 54517) | (4,731) | | | (4,731) |
| WDT-SIS:Soltage,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-DGCali-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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| 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-ApexEnergSolutionGasCoRoadSolar2 | (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-UniversalSlAircoupeSolar3((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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|---|---|---|---|---|
| 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-lp-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-lpTierraRobleIIEngStorage | (55,521) | 4,260 | 51,260 | |
| Rule21:DGS-CorcoraIrrigationDistrict-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-CALIFORNIARESOURCESCORPORATION | (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 |

| | | | | |
|---|---|---|---|---|
| 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-Borrego-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-2296WDByronHwy | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

| | | | | |
|---|---|---|---|---|
| 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-GentieLineRouteProp-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) |

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| 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) |

| | | | | |
|---|---|---|---|---|
| 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-BethelIslandCleanPwrOne | | 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 |

| | | | | |
|---|---|---|---|---|
| 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-BethelIslandCleanPowerOne | | | (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) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets | Balance at Beginning of Current Quarter/Year | Debits | CREDITS Written off During the Quarter/Year Account Charged | CREDITS Written off During the Period Amount | Balance at end of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 CHRG BA | 999,999,999 | 43,671,642 | 182.3 | 11,735,775 | 1,031,935,866 |
| 7 | NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA | 999,999,999 | | | | 999,999,999 |
| 8 | NEGATIVE ONGOING COMPETITION TRANSITION CHRG BA | 999,999,999 | | | | 999,999,999 |
| 9 | NEGATIVE ONGOING COMPETITION TRANSITION CHRG 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 Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 ADUST 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets<br>(a) | Balance at Beginning of Current Quarter/Year<br>(b) | Debits<br>(c) | CREDITS Written off During the Quarter/Year Account Charged<br>(d) | CREDITS Written off During the Period Amount<br>(e) | Balance at end of Current Quarter/Year<br>(f) |
|---|---|---|---|---|---|---|
| 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 Accout | | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets<br>(a) | Balance at Beginning of Current Quarter/Year<br>(b) | Debits<br>(c) | CREDITS<br>Written off During the Quarter/Year Account Charged<br>(d) | CREDITS<br>Written off During the Period Amount<br>(e) | Balance at end of Current Quarter/Year<br>(f) |
|---|---|---|---|---|---|---|
| 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 | CRTICAL 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 MORTAILITY 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 - DCPP 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |
| 7 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 7,027,240,817 | 81,757,684,690 | | 72,728,023,105 | 16,056,902,402 |

***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) |

| | |
|---|---|
| Line 25: | (999,999,999) |
| Line 26: | (999,999,999) |
| Line 27: | (842,395,313) |
| Total | (26,318,543,213) |

***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 | 3,257,964,692 |

***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 | 3,289,900,559 |

***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 | 6,733,275,805 |

***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 |

| | |
|---|---|
| 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 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

| Line No. | Description of Miscellaneous Deferred Debits (a) | Balance at Beginning of Year (b) | Debits (c) | CREDITS Account Charged (d) | CREDITS Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |
| 15 | | | | | | |
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| 46 | | | | | | |
| 47 | Misc. Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 45,196,485 | | | | 5,832,130,624 |

***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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

| Line No. | Description and Location<br>(a) | Balance of Begining of Year<br>(b) | Balance at End of Year<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

CAPITAL STOCKS (Account 201 and 204)

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

| Line No. | Class and Series of Stock and Name of Stock Series (a) | Number of shares Authorized by Charter (b) | Par or Stated Value per share (c) | Call Price at End of Year (d) |
|---|---|---|---|---|
| 1 | 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 | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

| OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent) | | HELD BY RESPONDENT | | | | Line No. |
|---|---|---|---|---|---|---|
| | | AS REACQUIRED STOCK (Account 217) | | IN SINKING AND OTHER FUNDS | | |
| Shares (e) | Amount (f) | Shares (g) | Cost (h) | Shares (i) | Amount (j) | |
| | | | | | | 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 |
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| 10,319,783 | 257,994,575 | | | | | 37 |
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***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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| 39 | | |
| 40 | TOTAL | 26,516,580,090 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## CAPITAL STOCK EXPENSE (Account 214)

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

| Line No. | Class and Series of Stock (a) | Balance at End of Year (b) |
|---|---|---|
| 1 | COMMON | 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 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |
| 21 | | |
| 22 | TOTAL | 28,951,886 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | | | 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 |
| 7 | | | |
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| 30 | | | |
| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 42,665,040,000 | 476,806,155 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| 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 Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| 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.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 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.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 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 |
| | | | | | | 7 |
| | | | | | | 8 |
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| | | | | | | 32 |
| | | | | 31,852,940,000 | 909,242,062 | 33 |

***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).

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Particulars (Details) (a) | Amount (b) |
|---|---|---|
| 1 | Net Income for the Year (Page 117) | 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 | | |

***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) |

| | | |
|---|---|---|
| DCPP 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 $ | (23,455,568,035) |

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

See footnote in row 12, column (b)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

| Line No. | Kind of Tax (See instruction 5) (a) | BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b) | Prepaid Taxes (Include in Account 165) (c) | Taxes Charged During Year (d) | Taxes Paid During Year (e) | Adjust-ments (f) |
|---|---|---|---|---|---|---|
| 1 | Federal - 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 - Decommisioning | | | 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 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 466,656,094 | | 683,356,025 | 717,597,819 | 21,170,715 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

| BALANCE AT END OF YEAR | | DISTRIBUTION OF TAXES CHARGED | | | | Line No. |
|---|---|---|---|---|---|---|
| (Taxes accrued Account 236) (g) | Prepaid Taxes (Incl. in Account 165) (h) | Electric (Account 408.1, 409.1) (i) | Extraordinary Items (Account 409.3) (j) | Adjustments to Ret. Earnings (Account 439) (k) | Other (l) | |
| 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 |
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| | | | | | | 40 |
| 453,585,015 | | 435,875,056 | | | 247,480,969 | 41 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

| Line No. | Account Subdivisions (a) | Balance at Beginning of Year (b) | Deferred for Year Account No. (c) | Deferred for Year Amount (d) | Allocations to Current Year's Income Account No. (e) | Allocations to Current Year's Income Amount (f) | Adjustments (g) |
|---|---|---|---|---|---|---|---|
| 1 | Electric Utility | | | | | | |
| 2 | 3% | | | | | | |
| 3 | 4% | | | | | | |
| 4 | 7% | | | | | | |
| 5 | 10% | 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 | | | | | | | |
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| 48 | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

| Balance at End of Year (h) | Average Period of Allocation to Income (i) | ADJUSTMENT EXPLANATION | Line No. |
|---|---|---|---|
| | | | 1 |
| | | | 2 |
| | | | 3 |
| | | | 4 |
| 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 |
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| | | | 48 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER DEFFERED CREDITS (Account 253)

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

| Line No. | Description and Other Deferred Credits<br>(a) | Balance at Beginning of Year<br>(b) | DEBITS Contra Account<br>(c) | DEBITS Amount<br>(d) | Credits<br>(e) | Balance at End of Year<br>(f) |
|---|---|---|---|---|---|---|
| 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 | | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | TOTAL | 242,148,049 | | 295,268,340 | 1,626,261,261 | 1,573,140,970 |

**_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).

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

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

| Line No. | Account | Balance at Beginning of Year | CHANGES DURING YEAR | |
|---|---|---|---|---|
| | | | Amounts Debited to Account 410.1 | Amounts Credited to Account 411.1 |
| | (a) | (b) | (c) | (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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

3. Use footnotes as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| Amounts Debited to Account 410.2 | Amounts Credited to Account 411.2 | Debits | | Credits | | | |
| | | Account Credited | Amount | Account Debited | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
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| | | | | | | | 21 |

NOTES (Continued)

***Schedule Page: 272 Line No.: 3 Column: b***

No activity in 2020.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

| Line No. | Account<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(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 | 8,462,844,659 | -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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

3. Use footnotes as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Amounts Debited to Account 410.2 | Amounts Credited to Account 411.2 | Debits | | Credits | | Balance at End of Year | Line No. |
| | | Account Credited | Amount | Account Debited | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | | | | 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)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

| Line No. | Account (a) | Balance at Beginning of Year (b) | CHANGES DURING YEAR Amounts Debited to Account 410.1 (c) | Amounts Credited to Account 411.1 (d) |
|---|---|---|---|---|
| 1 | Account 283 | | | |
| 2 | Electric | | | |
| 3 | 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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | | |
| Amounts Debited to Account 410.2<br>(e) | Amounts Credited to Account 411.2<br>(f) | Account Credited<br>(g) | Amount<br>(h) | Account Debited<br>(i) | Amount<br>(j) | Balance at End of Year<br>(k) | Line No. |
| | | | | | | | 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)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | Miscellanous 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 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

| Line No. | Title of Account<br>(a) | Operating Revenues Year to Date Quarterly/Annual<br>(b) | Operating Revenues Previous year (no Quarterly)<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC OPERATING REVENUES (Account 400)

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

| MEGAWATT HOURS SOLD | | AVG.NO. CUSTOMERS PER MONTH | | Line No. |
|---|---|---|---|---|
| Year to Date Quarterly/Annual (d) | Amount Previous year (no Quarterly) (e) | Current Year (no Quarterly) (f) | Previous Year (no Quarterly) (g) | |
| | | | | 1 |
| 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

**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 |
| 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 |
| | Total | 8,400,066 |

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

This consists of :

Unbilled revenues

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

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 |

| | |
|---|---|
| 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) | 141,667 |
| 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

| Line No. | Description of Service (a) | Balance at End of Quarter 1 (b) | Balance at End of Quarter 2 (c) | Balance at End of Quarter 3 (d) | Balance at End of Year (e) |
|---|---|---|---|---|---|
| 1 | NONE | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
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| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SALES OF ELECTRICITY BY RATE SCHEDULES

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

| Line No. | Number and Title of Rate schedule (a) | MWh Sold (b) | Revenue (c) | Average Number of Customers (d) | KWh of Sales Per Customer (e) | Revenue Per KWh Sold (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SALES FOR RESALE (Account 447)

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | | | 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** | |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 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) Mainentance 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 |
| | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 60 | D. Other Power Generation | | |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 113 | 3. REGIONAL MARKET EXPENSES | | |
| 114 | Operation | | |
| 115 | (575.1) Operation Supervision | | |
| 116 | (575.2) Day-Ahead and Real-Time Market Facilitation | | |
| 117 | (575.3) Transmission Rights Market Facilitation | | |
| 118 | (575.4) Capacity Market Facilitation | | |
| 119 | (575.5) Ancillary Services Market Facilitation | | |
| 120 | (575.6) Market Monitoring and Compliance | | |
| 121 | (575.7) Market Facilitation, Monitoring and Compliance Services | 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 Expns (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 |

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 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 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## PURCHASED POWER (Account 555)
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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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|---|---|---|---|---|---|---|
| 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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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 BELRIDGE 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 | FREEPORT MCMORAN DOME | LU | | 0.00000 | 2.70670 | N/A |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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)

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

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

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

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 PANOCHE (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) | Actual Demand (MW) 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 PANOCHE | | | 0.00000 | 0.00000 | |
| 13 | GAS TRANSPORT ASSOC. WITH MARSH | | | 0.00000 | 0.00000 | |
| 14 | GENESIS SOLAR, LLC | | | 0.00000 | 0.00000 | |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW): Average Monthly NCP Demand (e) | Actual Demand (MW): Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

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

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

PURCHASED POWER (Account 555)
(Including power exchanges)

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|---|---|---|
| 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 | PANOCHE 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 | | | | | |

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|---|---|---|---|---|---|---|
| 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 FIRMING | | | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

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

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

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## PURCHASED POWER (Account 555)
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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## PURCHASED POWER (Account 555)
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|---|---|---|---|---|---|---|
| 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 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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|---|---|---|---|---|---|---|
| 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 | | | | | |

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 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) | Actual Demand (MW) 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 | | | | | |

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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.

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| | | | | 19,601,937 | | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 | |

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

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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | -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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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)

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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) | |
| 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 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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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) | |
| | | | -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)

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) | |
| | | | | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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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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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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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) | |
| 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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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 |
| 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)

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) | |
| | | | 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.

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| -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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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 |
| 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.
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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.
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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) | |
| | | | | | 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 | This Report is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) X An Original<br>(2) __ A Resubmission | (Mo, Da, Yr)<br>04/13/2021 | 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 l 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | | | | |
| 2 | TRANSMISSION AGENCY OF | | | |
| 3 | NORTHERN CALIFORNIA (TANC) | Various | Various | LFP |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
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| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| | **TOTAL** | | | |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| 143 | Midway | Various | 233 | 553,931 | 543,456 | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| | | | | | | 8 |
| | | | | | | 9 |
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| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | **233** | **553,931** | **543,456** | |

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | | | | 1 |
| | | | | 2 |
| | 2,787,769 | 87,000 | 2,874,769 | 3 |
| | | | | 4 |
| | | | | 5 |
| | | | | 6 |
| | | | | 7 |
| | | | | 8 |
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| | | | | 32 |
| | | | | 33 |
| | | | | 34 |
| **0** | **2,787,769** | **87,000** | **2,874,769** | |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

| Line No. | Payment Received by (Transmission Owner Name) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Total Revenue by Rate Schedule or Tarirff (d) | Total Revenue (e) |
|---|---|---|---|---|---|
| 1 | NONE | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
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| 36 | | | | | |
| 37 | | | | | |
| 38 | | | | | |
| 39 | | | | | |
| 40 | TOTAL | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY: Magawatt-hours Received (c) | TRANSFER OF ENERGY: Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

***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 | | |
| 18 | | |
| 19 | | |
| 20 | | |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | | |
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| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |
| 45 | | |
| 46 | TOTAL | 27,790,938 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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

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

### A. Summary of Depreciation and Amortization Charges

| Line No. | Functional Classification (a) | Depreciation Expense (Account 403) (b) | Depreciation Expense for Asset Retirement Costs (Account 403.1) (c) | Amortization of Limited Term Electric Plant (Account 404) (d) | Amortization of Other Electric Plant (Acc 405) (e) | Total (f) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant | | | 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 | | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

| Line No. | Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a) | Assessed by Regulatory Commission (b) | Expenses of Utility (c) | Total Expense for Current Year (b) + (c) (d) | Deferred in Account 182.3 at Beginning of Year (e) |
|---|---|---|---|---|---|
| 1 | 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 | | | | | |
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| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | 12,177,885 | | 12,177,885 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

| EXPENSES INCURRED DURING YEAR | | | | AMORTIZED DURING YEAR | | | |
|---|---|---|---|---|---|---|---|
| CURRENTLY CHARGED TO | | | | | | | |
| Department (f) | Account No. (g) | Amount (h) | Deferred to Account 182.3 (i) | Contra Account (j) | Amount (k) | Deferred in Account 182.3 End of Year (l) | Line No. |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | 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 |
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| | | | | | | | 45 |
| | | 12,177,885 | | | | | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

| Line No. | Classification (a) | Description (b) |
|---|---|---|
| 1 | A2, A3 | Electric Program Investment Charge |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | A2, A3 | Customer Energy Services - |
| 7 | | |
| 8 | | |
| 9 | | |
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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 Account (e) | AMOUNTS CHARGED IN CURRENT YEAR Amount (f) | Unamortized Accumulation (g) | Line No. |
|---|---|---|---|---|---|
| -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 |
| | | | | | 9 |
| | | | | | 10 |
| | | | | | 11 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

| Line No. | Classification<br>(a) | Direct Payroll Distribution<br>(b) | Allocation of Payroll charged for Clearing Accounts<br>(c) | Total<br>(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 Terminaling 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 | | | | |
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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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT IN SERVICE

| Acct No. | Description | Balance Beginning of Year | Additions | Retirements | Transfers and Adjustments | Balance End 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 |

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

| | | | | | |
|---|---|---|---|---|---|
| 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 |

COMMON UTILITY PLANT AND EXPENSES

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4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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 | Account 408 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%

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 | Account 403 Gas |
|---|---|---|---|---|

COMMON UTILITY PLANT AND EXPENSES

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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

| Description | Amount Charged During Year | Account 935 Electric | Account 935 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 |

COMMON UTILITY PLANT AND EXPENSES

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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 DCPP 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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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

COMMON UTILITY PLANT AND EXPENSES

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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/Reliablity 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 - DCPP - 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

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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 Infras 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 |

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

| | | |
|---|---|---|
| 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 |

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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

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TOTAL CWIP - COMMON — $ 446,068,072

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

| Line No. | Description of Item(s) (a) | Balance at End of Quarter 1 (b) | Balance at End of Quarter 2 (c) | Balance at End of Quarter 3 (d) | Balance at End of Year (e) |
|---|---|---|---|---|---|
| 1 | Energy | | | | |
| 2 | Net Purchases (Account 555) | 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 | | | | | |
| 30 | | | | | |
| 31 | | | | | |
| 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.

| | | Amount Purchased for the Year | | | Amount Sold for the Year | | |
|---|---|---|---|---|---|---|---|
| | | Usage - Related Billing Determinant | | | Usage - Related Billing Determinant | | |
| Line No. | Type of Ancillary Service (a) | Number of Units (b) | Unit of Measure (c) | Dollars (d) | Number of Units (e) | Unit of Measure (f) | Dollars (g) |
| 1 | Scheduling, System Control and Dispatch | | | | | 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 |

**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 |
| ISO related AS activities | | | | | | |
| Retail ISO Purchases and Sales and Existing Transmission Contracts (ETC) (a) | - | Various | 2,169,879 | - | Various | 28,374,759 |
| Total | | | 2,169,879 | | | 28,374,759 |

(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 |

***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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

| Line No. | Month (a) | Monthly Peak MW - Total (b) | Day of Monthly Peak (c) | Hour of Monthly Peak (d) | Imports into ISO/RTO (e) | Exports from ISO/RTO (f) | Through and Out Service (g) | Network Service Usage (h) | Point-to-Point Service Usage (i) | Total Usage (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | | | | | | | | | |
| 2 | February | | | | | | | | | |
| 3 | March | | | | | | | | | |
| 4 | Total for Quarter 1 | | | | | | | | | |
| 5 | April | | | | | | | | | |
| 6 | May | | | | | | | | | |
| 7 | June | | | | | | | | | |
| 8 | Total for Quarter 2 | | | | | | | | | |
| 9 | July | | | | | | | | | |
| 10 | August | | | | | | | | | |
| 11 | September | | | | | | | | | |
| 12 | Total for Quarter 3 | | | | | | | | | |
| 13 | October | | | | | | | | | |
| 14 | November | | | | | | | | | |
| 15 | December | | | | | | | | | |
| 16 | Total for Quarter 4 | | | | | | | | | |
| 17 | Total Year to Date/Year | | | | | | | | | |
| | | | | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

| Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|
| 1 | SOURCES OF ENERGY | |
| 2 | Generation (Excluding Station Use): | |
| 3 | Steam | 5,892,957 |
| 4 | Nuclear | 16,284,423 |
| 5 | Hydro-Conventional | 6,285,290 |
| 6 | Hydro-Pumped Storage | 624,145 |
| 7 | Other | 777,026 |
| 8 | Less Energy for Pumping | 978,655 |
| 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 |

| Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|
| 21 | DISPOSITION OF ENERGY | |
| 22 | Sales to Ultimate Consumers (Including Interdepartmental Sales) | 36,530,075 |
| 23 | Requirements Sales for Resale (See instruction 4, page 311.) | 18,328,235 |
| 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | |
| 25 | Energy Furnished Without Charge | |
| 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | |
| 27 | Total Energy Losses | 33,401,185 |
| 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 88,259,495 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: PACIFIC GAS AND ELECTRIC COMPANY

| Line No. | Month (a) | Total Monthly Energy (b) | Monthly Non-Requirments Sales for Resale & Associated Losses (c) | MONTHLY PEAK Megawatts (See Instr. 4) (d) | MONTHLY PEAK Day of Month (e) | MONTHLY PEAK 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 | | | | |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

| Line No. | Item (a) | Plant Name: *DIABLO CANYON 1 & 2* (b) | | | Plant Name: *Colusa Gen Station* (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 | 0 | 18421187 | 0 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 0 | 0 | 0 | 1039182 | 0 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 0.000 | 0.000 | 0.000 | 3.580 | 0.000 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 53.442 | 0.000 | 0.000 | 3.570 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 0.653 | 0.000 | 0.000 | 3.430 | 0.000 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.007 | 0.000 | 0.000 | 0.020 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 10352.408 | 0.000 | 0.000 | 6302.000 | 0.000 | 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: *Gateway Gen Station* (d) | Plant Name: *Humboldt Gen Station* (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 |

| (d) | (d) | (d) | (e) | (e) | (e) | (f) | (f) | (f) | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

| Line No. | Item<br>(a) | FERC Licensed Project No. 175<br>Plant Name: BALCH NO. 1<br>(b) | FERC Licensed Project No. 175<br>Plant Name: BALCH NO. 2<br>(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 |

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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

| Line No. | Item (a) | FERC Licensed Project No. 2105<br>Plant Name: BUTT VALLEY<br>(b) | FERC Licensed Project No. 2105<br>Plant Name: CARIBOU NO. 1<br>(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 |

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## 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.
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| Line No. | Item (a) | FERC Licensed Project No. 803<br>Plant Name: DE SABLA<br>(b) | FERC Licensed Project No. 2310<br>Plant Name: DRUM NO. 1<br>(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 |

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## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
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| Line No. | Item<br>(a) | FERC Licensed Project No. 1988<br>Plant Name: HAAS<br>(b) | FERC Licensed Project No. 2130<br>Plant Name: HALSEY<br>(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 |

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## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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| Line No. | Item (a) | FERC Licensed Project No. 96<br>Plant Name: KERCKHOFF NO. 2<br>(b) | FERC Licensed Project No. 1988<br>Plant Name: KINGS RIVER<br>(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 |

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## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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| Line No. | Item (a) | FERC Licensed Project No. 233<br>Plant Name: PIT NO. 3<br>(b) | FERC Licensed Project No. 233<br>Plant Name: PIT NO. 4<br>(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 |

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## 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<br>Plant Name: POE<br>(b) | FERC Licensed Project No. 1962<br>Plant Name: ROCK CREEK<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

| Line No. | Item (a) | FERC Licensed Project No. 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

| Line No. | Item<br>(a) | FERC Licensed Project No. 0<br>Plant Name:<br>(b) | FERC Licensed Project No. 0<br>Plant Name:<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 2105<br>Plant Name: CARIBOU NO. 2<br>(d) | FERC Licensed Project No. 1121<br>Plant Name: COLEMAN<br>(e) | FERC Licensed Project No. 1962<br>Plant Name: CRESTA<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 2310<br>Plant Name: DRUM NO. 2<br>(d) | FERC Licensed Project No. 2310<br>Plant Name: DUTCH FLAT<br>(e) | FERC Licensed Project No. 137<br>Plant Name: ELECTRA<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 1403<br>Plant Name: NARROWS<br>(d) | FERC Licensed Project No. 2310<br>Plant Name: NEWCASTLE<br>(e) | FERC Licensed Project No. 2687<br>Plant Name: PIT NO.1<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| R of R/Storage | R of R/Storage | R of R/Storage | 1 |
| Conventional | Conventional | Conventional | 2 |
| 1942 | 1986 | 1922 | 3 |
| 1942 | 1986 | 1922 | 4 |
| 10.20 | 12.70 | 69.30 | 5 |
| 12 | 12 | 61 | 6 |
| 0 | 2,471 | 7,916 | 7 |
| | | | 8 |
| 12 | 12 | 61 | 9 |
| 12 | 0 | 61 | 10 |
| 0 | 0 | 0 | 11 |
| -63,288 | 7,131,112 | 182,376,839 | 12 |
| | | | 13 |
| -12 | 2,025,507 | 2,049,440 | 14 |
| -9 | 6,630,371 | 2,249,969 | 15 |
| 79,966 | 48,879,331 | 13,460,808 | 16 |
| -374,233 | 8,339,602 | 39,063,634 | 17 |
| -2 | 3,084,821 | 1,448,906 | 18 |
| 0 | 0 | 0 | 19 |
| -294,290 | 68,959,632 | 58,272,757 | 20 |
| -28.8520 | 5,429.8923 | 840.8767 | 21 |
| | | | 22 |
| 0 | 0 | 0 | 23 |
| 152,745 | 13,432 | 51,762 | 24 |
| 0 | 11,863 | 11,824 | 25 |
| 12,937 | 110,640 | 146,555 | 26 |
| 3,345 | 2,395 | 522,089 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 0 | 407 | 32,269 | 30 |
| 19,682 | 1,737,099 | 226,329 | 31 |
| 3,756 | 116,289 | 320,844 | 32 |
| 0 | 777,006 | 66,688 | 33 |
| 192,465 | 2,769,131 | 1,378,360 | 34 |
| 0.0000 | 0.3883 | 0.0076 | 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. 233<br>Plant Name: PIT NO. 5<br>(d) | FERC Licensed Project No. 2106<br>Plant Name: PIT NO. 6<br>(e) | FERC Licensed Project No. 2106<br>Plant Name: PIT NO. 7<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| R of R/Storage | R of R/Storage | R of R/Storage | 1 |
| Conventional | Outdoor | Outdoor | 2 |
| 1944 | 1965 | 1965 | 3 |
| 1944 | 1965 | 1965 | 4 |
| 141.84 | 79.20 | 109.80 | 5 |
| 160 | 80 | 112 | 6 |
| 8,784 | 6,304 | 8,331 | 7 |
| | | | 8 |
| 160 | 80 | 112 | 9 |
| 160 | 80 | 112 | 10 |
| 0 | 0 | 0 | 11 |
| 547,242,680 | 194,070,518 | 311,413,199 | 12 |
| | | | 13 |
| 647,714 | 414,645 | 356,018 | 14 |
| 18,876,047 | 6,212,220 | 5,978,260 | 15 |
| 45,534,631 | 36,662,218 | 32,655,908 | 16 |
| 89,496,343 | 26,634,990 | 24,233,874 | 17 |
| 8,953,497 | 687,466 | 406,277 | 18 |
| 0 | 0 | 0 | 19 |
| 163,508,232 | 70,611,539 | 63,630,337 | 20 |
| 1,152.7653 | 891.5598 | 579.5113 | 21 |
| | | | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 16,236 | 16,099 | 24 |
| 30,918 | 11,655 | 8,688 | 25 |
| 1,761,722 | 423,852 | 428,307 | 26 |
| 897,257 | 139,889 | 138,707 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 51,762 | 21,100 | 33,566 | 30 |
| 120,951 | 17,469 | 392,755 | 31 |
| 391,078 | 382,799 | 320,373 | 32 |
| 164,280 | 34,174 | 77,410 | 33 |
| 3,417,968 | 1,047,174 | 1,415,905 | 34 |
| 0.0062 | 0.0054 | 0.0045 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 137<br>Plant Name: SALT SPRINGS<br>(d) | FERC Licensed Project No. 2130<br>Plant Name: STANISLAUS<br>(e) | FERC Licensed Project No. 137<br>Plant Name: TIGER CREEK<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| R of R/Storage | R of R/Storage | R of R/Storage | 1 |
| Conventional | Outdoor | Conventional | 2 |
| 1931 | 1963 | 1931 | 3 |
| 1953 | 1963 | 1931 | 4 |
| 42.03 | 81.90 | 52.28 | 5 |
| 44 | 91 | 58 | 6 |
| 7,123 | 7,882 | 7,591 | 7 |
| | | | 8 |
| 44 | 91 | 58 | 9 |
| 34 | 91 | 58 | 10 |
| 0 | 0 | 0 | 11 |
| 109,081,748 | 240,723,747 | 235,205,760 | 12 |
| | | | 13 |
| 195,719 | 428,811 | 2,499,715 | 14 |
| 2,401,784 | 7,041,739 | 8,890,852 | 15 |
| 36,156,785 | 38,401,614 | 80,018,641 | 16 |
| 13,529,600 | 20,550,135 | 29,346,788 | 17 |
| 1,634,846 | 1,071,183 | 8,105,773 | 18 |
| 0 | 0 | 0 | 19 |
| 53,918,734 | 67,493,482 | 128,861,769 | 20 |
| 1,282.8631 | 824.0962 | 2,464.8387 | 21 |
| | | | 22 |
| 0 | 0 | 0 | 23 |
| 7,336 | 426,212 | 8,755 | 24 |
| 337,239 | 36,718 | 383,973 | 25 |
| 639,564 | 632,605 | 1,106,844 | 26 |
| 53,310 | 109,013 | 63,622 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 58,623 | 27,767 | 261,951 | 30 |
| 799,874 | 1,307,334 | 2,379,696 | 31 |
| 736,772 | 333,899 | 1,052,358 | 32 |
| 114,664 | 82,337 | 69,927 | 33 |
| 2,747,382 | 2,955,885 | 5,327,126 | 34 |
| 0.0252 | 0.0123 | 0.0226 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

| FERC Licensed Project No. 0<br>Plant Name:<br>(d) | FERC Licensed Project No. 0<br>Plant Name:<br>(e) | FERC Licensed Project No. 0<br>Plant Name:<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| | | | 1 |
| | | | 2 |
| | | | 3 |
| | | | 4 |
| 0.00 | 0.00 | 0.00 | 5 |
| 0 | 0 | 0 | 6 |
| 0 | 0 | 0 | 7 |
| | | | 8 |
| 0 | 0 | 0 | 9 |
| 0 | 0 | 0 | 10 |
| 0 | 0 | 0 | 11 |
| 0 | 0 | 0 | 12 |
| | | | 13 |
| 0 | 0 | 0 | 14 |
| 0 | 0 | 0 | 15 |
| 0 | 0 | 0 | 16 |
| 0 | 0 | 0 | 17 |
| 0 | 0 | 0 | 18 |
| 0 | 0 | 0 | 19 |
| 0 | 0 | 0 | 20 |
| 0.0000 | 0.0000 | 0.0000 | 21 |
| | | | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 0 | 0 | 0 | 25 |
| 0 | 0 | 0 | 26 |
| 0 | 0 | 0 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 0 | 0 | 0 | 30 |
| 0 | 0 | 0 | 31 |
| 0 | 0 | 0 | 32 |
| 0 | 0 | 0 | 33 |
| 0 | 0 | 0 | 34 |
| 0.0000 | 0.0000 | 0.0000 | 35 |

**Schedule Page: 406 Line No.: 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 HEADQUATERS: | NUMER OF OPERATORS: | MAINTENANCE HEADQUATERS: | 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 | Y | | | | | | |
| 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 | 16 |
| | | | | | | Sonora Service Center | 7 |
| 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

| Line No. | Item (a) | FERC Licensed Project No. 2735<br>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 Demaind 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

| FERC Licensed Project No. 0<br>Plant Name:<br>(c) | FERC Licensed Project No. 0<br>Plant Name:<br>(d) | FERC Licensed Project No. 0<br>Plant Name:<br>(e) | Line No. |
|---|---|---|---|
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| | | | 38 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

| Line No. | Name of Plant (a) | Year Orig. Const. (b) | Installed Capacity Name Plate Rating (In MW) (c) | Net Peak Demand MW (60 min.) (d) | Net Generation Excluding Plant Use (e) | Cost of Plant (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |
| 46 | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

| Line No. | Name of Plant (a) | Year Orig. Const. (b) | Installed Capacity Name Plate Rating (In MW) (c) | Net Peak Demand MW (60 min.) (d) | Net Generation Excluding Plant Use (e) | Cost of Plant (f) |
|---|---|---|---|---|---|---|
| 1 | 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 |
| 10 | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

| Plant Cost (Incl Asset Retire. Costs) Per MW (g) | Operation Exc'l. Fuel (h) | Production Expenses Fuel (i) | Production Expenses Maintenance (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 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 |
| | | | | | | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

| Plant Cost (Incl Asset Retire. Costs) Per MW (g) | Operation Exc'l. Fuel (h) | Production Expenses Fuel (i) | Production Expenses Maintenance (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 5,315,314 | 262,677 | | 345,810 | Natural Gas | | 2 |
| 4,701,886 | 142,200 | | 183,191 | Natural Gas | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | Diesel | | 7 |
| | | | | Diesel | | 8 |
| | | | | Diesel | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
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***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.

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | STELLING | MONTA VISTA | 115.00 | 115.00 | T SSP | 1.61 | | 1 |
| 2 | LAS AGUILAS SW STA | PANOCHE #2 | 230.00 | 230.00 | SSP | 17.44 | | 1 |
| 3 | LAS AGUILAS SW STA | PANOCHE #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 | PANOCHE | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 | CERTAINTEED 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 | ULTRAPOWER (OGLE) TAP | | 115.00 | 115.00 | SWP SSP | 2.45 | | 1 |
| 36 | | | | | TOTAL | 36,671.97 | | 1,451 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 | PANOCHE | PANOCHE 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 |

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|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 | PANOCHE | MENDOTA | 115.00 | 115.00 | SWP SSP | 10.08 | | 1 |
| 36 | | | | | TOTAL | 36,671.97 | | 1,451 |

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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | CHENEY #1 TAP | | 115.00 | 115.00 | SWP T SSP | 4.10 | | 1 |
| 2 | PANOCHE | 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 | PANOCHE | 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 | PANOCHE | 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 |

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| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |
| 36 | | | | | TOTAL | 36,671.97 | | 1,451 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS

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| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | PANOCHE | 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 | PANOCHE #1 | 230.00 | 230.00 | T SSP | 43.79 | | 1 |
| 27 | GATES | PANOCHE #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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 | PANOCHE | 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 | PANOCHE | 230.00 | 230.00 | T SSP | 33.58 | | 1 |
| 32 | LOS BANOS | PANOCHE #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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | Structure (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 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 | PANOCHE | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

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## TRANSMISSION LINE STATISTICS

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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | COOLEY LANDING | LOS ALTOS | 60.00 | 60.00 | SWP T SSP | 14.89 | | 1 |
| 2 | COOLEY LANDING | LOS ALTOS (I2KV) | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | SENTER #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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

# TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 | WOODBRIDGE 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
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| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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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## TRANSMISSION LINE STATISTICS

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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 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 |

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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

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| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION | | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) | | Type of Supporting Structure | LENGTH (Pole miles) (In the case of underground lines report circuit miles) | | Number Of Circuits |
|---|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | Operating (c) | Designed (d) | (e) | On Structure of Line Designated (f) | On Structures of Another Line (g) | (h) |
| 1 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS (Continued)

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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.
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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) | |
| 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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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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|---|---|---|---|---|---|---|---|---|
| (i) | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| | Land | Construction and Other Costs | Total Cost | Operation Expenses | Maintenance Expenses | Rents | Total Expenses | |
| (i) | (j) | (k) | (l) | (m) | (n) | (o) | (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 |

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TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

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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) | |
| 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 |

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TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| 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 |

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TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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| Size of Conductor and Material<br>(i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)<br>Land<br>(j) | Construction and Other Costs<br>(k) | Total Cost<br>(l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES<br>Operation Expenses<br>(m) | Maintenance Expenses<br>(n) | Rents<br>(o) | Total Expenses<br>(p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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)

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| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | 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 |
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## TRANSMISSION LINE STATISTICS (Continued)

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| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |
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TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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|---|---|---|---|---|---|---|---|---|
| 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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| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 336.4 - 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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## TRANSMISSION LINE STATISTICS (Continued)

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| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS (Continued)

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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 |
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| (i) | 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)

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| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | 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 |
| 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)

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| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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## TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1/0 - 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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 |
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|---|---|---|---|---|---|---|---|---|
| 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 |
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TRANSMISSION LINE STATISTICS (Continued)

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|---|---|---|---|---|---|---|---|---|
| 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 |
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|---|---|---|---|---|---|---|---|---|
| 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 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1/0 - 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

| Size of Conductor and Material | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 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 |

***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

***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

***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<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

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 | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) X An Original<br>(2) __ A Resubmission | 04/13/2021 | 2020/Q4 |

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
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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
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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
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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

***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

**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
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Information not available as of the date of this report
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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

***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

***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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

| Line No. | LINE DESIGNATION From (a) | LINE DESIGNATION To (b) | Line Length in Miles (c) | SUPPORTING STRUCTURE Type (d) | SUPPORTING STRUCTURE Average Number per Miles (e) | CIRCUITS PER STRUCTURE Present (f) | CIRCUITS PER STRUCTURE Ultimate (g) |
|---|---|---|---|---|---|---|---|
| 1 | 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 hybris | 2.90 | 1 | 1 |
| 27 | Job Order # 74001396 | | | | | | |
| 28 | | | | | | | |
| 29 | (DA-B&M) ELECTRA-VALLEY | | | | | | |
| 30 | Electric Substation | Vallley 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

| Line No. | LINE DESIGNATION From (a) | LINE DESIGNATION To (b) | Line Length in Miles (c) | SUPPORTING STRUCTURE Type (d) | SUPPORTING STRUCTURE Average Number per Miles (e) | CIRCUITS PER STRUCTURE Present (f) | CIRCUITS PER STRUCTURE Ultimate (g) |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

| Line No. | LINE DESIGNATION From (a) | LINE DESIGNATION To (b) | Line Length in Miles (c) | SUPPORTING STRUCTURE Type (d) | SUPPORTING STRUCTURE Average Number per Miles (e) | CIRCUITS PER STRUCTURE Present (f) | CIRCUITS PER STRUCTURE Ultimate (g) |
|---|---|---|---|---|---|---|---|
| 1 | 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 | | | | | | | |
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| 40 | | | | | | | |
| 41 | | | | | | | |
| 42 | | | | | | | |
| 43 | | | | | | | |
| 44 | TOTAL | | 70.67 | | 375.84 | 22 | 22 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

| CONDUCTORS | | | Voltage KV (Operating) | LINE COST | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | (k) | 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 |
| | | | | 12,952,223 | 71,804,969 | 40,607,541 | | 125,364,733 | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

| CONDUCTORS | | | Voltage | LINE COST | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | KV (Operating) (k) | Land and Land Rights (l) | Poles, Towers and Fixtures (m) | Conductors and Devices (n) | Asset Retire. Costs (o) | Total (p) | |
| | | | | | | | | | 1 |
| | | | | | | | | | 2 |
| 397.5 | KCM | various | 60 | 8,381 | 1,892,005 | 715,514 | | 2,615,900 | 3 |
| | | | | | | | | | 4 |
| | | | | | | | | | 5 |
| | | | | | | | | | 6 |
| | | | | | | | | | 7 |
| 715.5 | KCM | various | 60 | 445 | 1,144,298 | 12,838 | | 1,157,581 | 8 |
| | | | | | | | | | 9 |
| | | | | | | | | | 10 |
| | | | | | | | | | 11 |
| 4/0 | AWG | various | 70 | 37 | 2,673 | 364 | | 3,074 | 12 |
| | | | | | | | | | 13 |
| | | | | | | | | | 14 |
| 1113 | KCM | various | 115 | 22,948 | 1,245,520 | -387,184 | | 881,284 | 15 |
| | | | | | | | | | 16 |
| | | | | | | | | | 17 |
| | | | | | | | | | 18 |
| | | | | | | | | | 19 |
| 250 | KCML | various | 115 | 16,309 | 428,066 | 113,289 | | 557,664 | 20 |
| | | | | | | | | | 21 |
| | | | | | | | | | 22 |
| 715.5 | KCM | various | 60 | | 237,878 | 477,089 | | 714,967 | 23 |
| | | | | | | | | | 24 |
| | | | | | | | | | 25 |
| | | | | | | | | | 26 |
| 715.5 | KCM | various | 60 | | -131,930 | -38,390 | | -170,320 | 27 |
| | | | | | | | | | 28 |
| | | | | | | | | | 29 |
| | | | | | | | | | 30 |
| 397.5 | KCM | various | 60 | 483,961 | 39,195,089 | 8,096,795 | | 47,775,845 | 31 |
| | | | | | | | | | 32 |
| | | | | | | | | | 33 |
| | | | | | | | | | 34 |
| 715.5 | KCM | various | 60 | 110,472 | 1,504,066 | 2,438,426 | | 4,052,964 | 35 |
| | | | | | | | | | 36 |
| | | | | | | | | | 37 |
| | | | | | | | | | 38 |
| 4/0 | AWG | various | 60 | 27,249 | 74,561 | 133,408 | | 235,218 | 39 |
| | | | | | | | | | 40 |
| | | | | | | | | | 41 |
| | | | | | | | | | 42 |
| 715.5 | KCM | various | 115 | | -66,064 | 951 | | -65,113 | 43 |
| | | | | 12,952,223 | 71,804,969 | 40,607,541 | | 125,364,733 | 44 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

| CONDUCTORS | | | 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 |
| | | | | | | | | | 9 |
| | | | | | | | | | 10 |
| | | | | | | | | | 11 |
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| | | | | | | | | | 43 |
| | | | | 12,952,223 | 71,804,969 | 40,607,541 | | 125,364,733 | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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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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 | PANOCHE SUB, 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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## 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 | 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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|---|---|---|---|---|---|
| 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 |

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|---|---|---|---|---|---|
| 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, Ione | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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, McKitrick | 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. Sactramento | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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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 | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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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 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
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SUBSTATIONS

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|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
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| Line No. | Name and Location of Substation<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa) Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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 | PANOCHE 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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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## 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.
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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 | 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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## SUBSTATIONS

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| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (e) |
| 1 | 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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| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) 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, Leboc | 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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| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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, Orosi | 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 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | 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) | | | | |
| 11 | | | | | |
| 12 | | | | | |
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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| Capacity of Substation (In Service) (In MVa)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

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|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

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|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

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|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original (2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 45 | 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 45 | 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 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 |

| Name of Respondent<br>PACIFIC GAS AND ELECTRIC COMPANY | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/13/2021 | Year/Period of Report<br>End of 2020/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 |

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment | Number of Units | Total Capacity (In MVa) | Line No. |
|---|---|---|---|---|---|---|
| (f) | (g) | (h) | (i) | (j) | (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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 6 | 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 |
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| | | | | | | 31 |
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| | | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |

***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 >=60kV and secondary voltage >= 60kV) 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 <10MVA. There are 664 substations with distribution transformer banks. (605+59 = 664)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

| Line No. | Description of the Non-Power Good or Service<br>(a) | Name of Associated/Affiliated Company<br>(b) | Account Charged or Credited<br>(c) | Amount Charged or Credited<br>(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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| PACIFIC GAS AND ELECTRIC COMPANY | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/13/2021 | End of 2020/Q4 |

## TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

| Line No. | Description of the Non-Power Good or Service (a) | Name of Associated/Affiliated Company (b) | Account Charged or Credited (c) | Amount Charged or Credited (d) |
|---|---|---|---|---|
| 3 | | | | |
| 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 | | | | |

***Schedule Page: 429 Line No.: 10 Column: a***

**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 |

# INDEX

| Schedule | Page No. |
|---|---|

Schedule | Page No.

Schedule | Page No.