UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2021

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number	Exact Name of Registrant as Specified In Its Charter	State or Other Jurisdiction of Incorporation or Organization	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

77 Beale Street
P.O. Box 770000
San Francisco, California 94117
(Address of principal executive offices) (Zip Code)
415 973-1000
(Registrant's telephone number, including area code)

77 Beale Street
P.O. Box 770000
San Francisco, California 94117
(Address of principal executive offices) (Zip Code)
415 973-1000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, no par value	PCG	The New York Stock Exchange
Equity Units	PCGU	The New York Stock Exchange
First preferred stock, cumulative, par value $25 per share, 5% series A redeemable	PCG-PE	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 5% redeemable	PCG-PD	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 4.80% redeemable	PCG-PG	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 4.50% redeemable	PCG-PH	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 4.36% series A redeemable	PCG-PI	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 6% nonredeemable	PCG-PA	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 5.50% nonredeemable	PCG-PB	NYSE American LLC
First preferred stock, cumulative, par value $25 per share, 5% nonredeemable	PCG-PC	NYSE American LLC

Securities registered pursuant to Section 12(g) of the Act: none

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

PG&E Corporation:	☐ Yes	☒ No
Pacific Gas and Electric Company:	☐ Yes	☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

PG&E Corporation	**Pacific Gas and Electric Company**
☒ Large accelerated filer	☐ Large accelerated filer
☐ Non-accelerated filer	☒ Non-accelerated filer
☐ Smaller reporting company	☐ Smaller reporting company
☐ Accelerated filer	☐ Accelerated filer
☐ Emerging growth company	☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

PG&E Corporation:	☐
Pacific Gas and Electric Company:	☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

PG&E Corporation:	☒
Pacific Gas and Electric Company:	☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation:	☐ Yes	☒ No
Pacific Gas and Electric Company:	☐ Yes	☒ No

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.

PG&E Corporation:	☒ Yes	☐ No
Pacific Gas and Electric Company:	☒ Yes	☐ No

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2021, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$20,185 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 4, 2022:

PG&E Corporation:	2,463,891,104*
Pacific Gas and Electric Company:	264,374,809

*Includes 437,743,590 shares of common stock held by PG&E ShareCo LLC, a wholly-owned subsidiary of PG&E Corporation, and 40,000,000 shares of common stock held by Pacific Gas and Electric Company.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the Joint Proxy Statement relating to the 2021 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

Contents

UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1 Bcf	=	One billion cubic feet
1 MDth	=	One thousand decatherms

GLOSSARY

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

2021 Form 10-K	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2021
AB	Assembly Bill
AFUDC	Allowance for Funds Used During Construction
Amended Articles	Amended and Restated Articles of Incorporation of PG&E Corporation and the Utility, each filed on June 22, 2020
ARO	asset retirement obligation
ASU	accounting standard update issued by the FASB
Bankruptcy Code	the United States Bankruptcy Code
Bankruptcy Court	the U.S. Bankruptcy Court for the Northern District of California
BPP	bundled procurement plan
CAISO	California Independent System Operator Corporation
Cal Fire	California Department of Forestry and Fire Protection
CAPP	California Arrearage Payment Program
CARB	California Air Resources Board
CARE	California Alternate Rates for Energy Program
CCA	Community Choice Aggregator
CCPA	California Consumer Privacy Act of 2018
CEC	California Energy Resources Conservation and Development Commission
CEMA	Catastrophic Event Memorandum Account
Chapter 11	Chapter 11 of Title 11 of the U.S. Code
Chapter 11 Cases	the voluntary cases commenced by each of PG&E Corporation and the Utility under Chapter 11 on January 29, 2019
Confirmation Order	the order confirming the Plan, dated as of June 20, 2020 with the Bankruptcy Court
CHT	Customer Harm Threshold
CPIM	Core Procurement Incentive Mechanism
CPPMA	COVID-19 Pandemic Protections Memorandum Account
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
CVA	Climate Vulnerability Assessment
DA	Direct Access
Diablo Canyon	Diablo Canyon nuclear power plant
DOE	U.S. Department of Energy
DTA	deferred tax asset
DTSC	Department of Toxic Substances Control
EMANI	European Mutual Association for Nuclear Insurance
Emergence Date	July 1, 2020, the effective date of the Plan in the Chapter 11 Cases
EO	Executive Order
EOEP	Enhanced Oversight and Enforcement Process
EPA	U.S. Environmental Protection Agency
EPS	earnings per common share
EPSS	Enhanced Powerline Safety Settings
EV	electric vehicle
EVM	enhanced vegetation management
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board

FERC	Federal Energy Regulatory Commission
FHPMA	Fire Hazard Prevention Memorandum Account
Fire Victim Trust	The trust established pursuant to the Plan for the benefit of holders of the Fire Victim Claims into which the Aggregate Fire Victim Consideration (as defined in the Plan) has been, and will continue to be funded
FRMMA	Fire Risk Mitigation Memorandum Account
GAAP	U.S. Generally Accepted Accounting Principles
GHG	greenhouse gas
GO	general order
GRC	general rate case
GT&S	gas transmission and storage
HFTD	high fire-threat districts as set forth in the CPUC Fire-Threat Map
HSM	hazardous substance memorandum account
IRC	Internal Revenue Code
IRP	Integrated Resource Planning
IOUs	investor-owned utility(ies)
Kincade Amended Complaint	The amended criminal complaint filed by the Sonoma County District Attorney's Office on January 28, 2022 in connection with the 2019 Kincade fire
Kincade Complaint	The criminal complaint filed by the Sonoma County District Attorney's Office on April 6, 2021 in connection with the 2019 Kincade fire
Lakeside Building	300 Lakeside Drive, Oakland, California, 94612
LIBOR	London Interbank Offered Rate
LSE	Load-serving entity
LTIP	Long-Term Incentive Plan (including the PG&E Corporation 2021 Long-Term Incentive Plan and its predecessor, the PG&E Corporation 2014 Long-Term Incentive Plan)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K
MGMA	Microgrids Memorandum Account
MGP	manufactured gas plants
the Monitor	third-party monitor retained by the Utility as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction
NAV	net asset value
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
OEIS	Office of Energy Infrastructure Safety (successor to the Wildfire Safety Division of the CPUC)
OII	order instituting investigation
OIR	order instituting rulemaking
PCAOB	Public Company Accounting Oversight Board (United States)
PD	proposed decision
PERA	Public Employees Retirement Association
Petition Date	January 29, 2019
Plan	PG&E Corporation and the Utility, Knighthead Capital Management, LLC, and Abrams Capital Management, LP Joint Chapter 11 Plan of Reorganization, dated as of June 19, 2020
POD	Presiding Officer's Decision
PSPS	Public Safety Power Shutoff
QF	Qualifying facilities
RAMP	Risk Assessment Mitigation Phase

RA	Resource Adequacy
ROE	return on equity
ROU asset	right-of-use asset
RPS	Renewables Portfolio Standard
RSA	restructuring support agreement
RTBA	Risk Transfer Balancing Account
RUBA	Residential Uncollectibles Balancing Account
SB	Senate Bill
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
SFGO	The Utility's San Francisco General Office headquarters complex
ShareCo	PG&E ShareCo LLC, a limited liability company whose sole member is PG&E Corporation
SPV	PG&E AR Facility, LLC
Tax Act	Tax Cuts and Jobs Act of 2017
TCC	Official Committee of Tort Claimants
TCC RSA	Restructuring Support Agreement dated December 6, 2019 with the TCC and attorneys and other advisors and agents for certain holders of Fire Victim Claims (as defined therein), as amended
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)
VMBA	Vegetation Management Balancing Account
WEMA	Wildfire Expense Memorandum Account
Wildfire Fund	statewide fund established by AB 1054 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
Wildfires OII	Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire
WMBA	Wildfire Mitigation Balancing Account
WMCE	Wildfire Mitigation and Catastrophic Events
WMP	wildfire mitigation plan
WMPMA	Wildfire Mitigation Plan Memorandum Account
Zogg Complaint	The criminal complaint filed by the Shasta County District Attorney's Office on September 24, 2021

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of capital expenditures; forecasts of expense reduction; estimates and assumptions used in critical accounting estimates, including those relating to insurance receivables, regulatory assets and liabilities, environmental remediation, litigation, third-party claims, the Wildfire Fund, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the extent to which the Wildfire Fund and revised recoverability standard under AB 1054 effectively mitigates the risk of liability for damages arising from catastrophic wildfires, including whether the Utility maintains an approved WMP and a valid safety certification and whether the Wildfire Fund has sufficient remaining funds;

- the risks and uncertainties associated with wildfires that have occurred or may occur in the Utility's service territory, including the wildfire that began on October 23, 2019 northeast of Geyserville in Sonoma County, California (the "2019 Kincade fire"), the wildfire that began on September 27, 2020 in the area of Zogg Mine Road and Jenny Bird Lane, north of Igo in Shasta County, California (the "2020 Zogg fire"), the wildfire that began on July 13, 2021 near the Cresta Dam in the Feather River Canyon in Plumas County, California (the "2021 Dixie fire"), and any other wildfires for which the causes have yet to be determined; the damage caused by such wildfires; the extent of the Utility's liability in connection with such wildfires (including the risk that the Utility may be found liable for damages regardless of fault); investigations into such wildfires, including those being conducted by the CPUC and various district attorney's offices; the outcome of the criminal proceedings initiated against the Utility in connection with the 2019 Kincade fire, the 2020 Zogg fire, and three other fires; potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other enforcement agency were to bring an enforcement action in respect of any such fire; the risk that the Utility is not able to recover costs from insurance, from the Wildfire Fund or through rates; and the effect on PG&E Corporation's and the Utility's reputations of such wildfires, investigations and proceedings;

- the extent to which the Utility's wildfire mitigation initiatives are effective, including the Utility's ability to comply with the targets and metrics set forth in its WMP; to retain or contract for the workforce necessary to execute its WMP; the effectiveness of its system hardening, including undergrounding; and the cost of the program and the timing and outcome of any proceeding to recover such costs through rates;

- the impact of the Utility's implementation of its PSPS program, and whether any fines, penalties or civil liability for damages will be imposed on the Utility as a result; the costs in connection with PSPS events, the timing and outcome of any proceeding to recover such costs through rates, and the effects on PG&E Corporation's and the Utility's reputations caused by implementation of the PSPS program;

- the Utility's ability to safely, reliably, and efficiently construct, maintain, operate, protect, and decommission its facilities, and provide electricity and natural gas services safely and reliably;

- the availability, cost, coverage, and terms of the Utility's insurance, including insurance for wildfire, nuclear, and other liabilities, the timing of any insurance recoveries, and recovery of the costs of such insurance or, in the event liabilities exceed insured amounts, the ability to recover uninsured losses through rates or from other third parties;

- significant changes to the electric power and gas industries driven by technological advancements and a decarbonized economy;

- cyber or physical attacks, including acts of terrorism, war, and vandalism, on the Utility or its third-party vendors, contractors, or customers (or others with whom they have shared data) which could result in operational disruption; the misappropriation or loss of confidential or proprietary assets, information or data, including customer, employee, financial, or operating system information, or intellectual property; corruption of data; or potential costs, lost revenues, or reputational harm incurred in connection therewith;

- the impact of severe weather events and other natural disasters, including wildfires and other fires, storms, tornadoes, floods, extreme heat events, drought, earthquakes, lightning, tsunamis, rising sea levels, mudslides, pandemics, solar events, electromagnetic events, wind events or other weather-related conditions, climate change, or natural disasters, and other events that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the effectiveness of the Utility's efforts to prevent or respond to such conditions or events; the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; whether the Utility is able to procure replacement power; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events;

- the ability of the Utility to meet the conditions in its corrective action plan and exit the EOEP;

- the timing and outcome of future regulation and federal, state or local legislation, their implementation, and their interpretation; the cost to comply with such regulation and legislation; and the extent to which the Utility recovers its associated compliance and investment costs, including those regarding:

    - wildfires, including inverse condemnation reform, wildfire insurance, and additional wildfire mitigation measures or other reforms targeted at the Utility or its industry;

    - the environment, including the costs incurred to discharge the Utility's remediation obligations or the costs to comply with standards for GHG emissions, renewable energy targets, energy efficiency standards, distributed energy resources, and EVs;

    - the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, and cooling water intake, and the Utility's ability to continue operating Diablo Canyon until its planned retirement;

    - the regulation of utilities and their holding companies, including the conditions imposed on PG&E Corporation when it became the Utility's holding company and whether the Utility can make distributions to PG&E Corporation; and

    - taxes and tax audits;

- the timing and outcomes of the Utility's pending and future ratemaking and regulatory proceedings, including the extent to which PG&E Corporation and the Utility are able to recover their costs through rates as recorded in memorandum accounts or balancing accounts, or as otherwise requested;

- whether the Utility can control its operating costs within the authorized levels of spending, and timely recover its costs through rates; whether the Utility can continue implementing a streamlined organizational structure and achieve projected savings; the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

- the outcome of current and future self-reports, investigations or other enforcement actions, or notices of violation that could be issued related to the Utility's compliance with laws, rules, regulations, or orders applicable to its gas and electric operations; the construction, expansion, or replacement of its electric and gas facilities; electric grid reliability; audit, inspection and maintenance practices; customer billing and privacy; physical and cybersecurity protections; environmental laws and regulations; or otherwise, such as fines, penalties, remediation obligations, the transfer of ownership of the Utility's assets to municipalities or other public entities, or the implementation of corporate governance, operational or other changes in connection with the EOEP;

- the risks and uncertainties associated with PG&E Corporation's and the Utility's substantial indebtedness and the limitations on their operating flexibility in the documents governing that indebtedness;

- the risks and uncertainties associated with the timing and outcomes of PG&E Corporation's and the Utility's ongoing litigation, including appeals of the Confirmation Order; certain indemnity obligations to current and former officers and directors, as well as potential indemnity obligations to underwriters for certain of the Utility's note offerings; three purported class actions 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; the appeal of the FERC's order denying rehearing on March 17, 2020 granting the Utility a 50-basis point ROE incentive adder for continued participation in the CAISO; the debarment proceeding; the purported PSPS class action filed in December 2019; and other third-party claims, including the extent to which related costs can be recovered through insurance, rates, or from other third parties;

- the ability of PG&E Corporation and the Utility to securitize (i) the remaining $2.4 billion of fire risk mitigation capital expenditures that were or will be incurred by the Utility and (ii) $7.5 billion of costs related to the multiple wildfires that began on October 8, 2017 and 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"), in a financing transaction that is designed to be rate neutral to customers;

- the risks and uncertainties associated with any future substantial sales of shares of common stock of PG&E Corporation by existing shareholders, including the Fire Victim Trust;

- whether PG&E Corporation or the Utility undergoes an "ownership change" within the meaning of Section 382 of the IRC, as a result of which tax attributes could be limited;

- PG&E Corporation's and the Utility's historical financial information not being indicative of future financial performance as a result of the Chapter 11 Cases and the financial and other restructuring undergone by PG&E Corporation and the Utility in connection with their emergence from Chapter 11;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California and the Utility's fossil fuel-fired generation sites;

- the impact that reductions in Utility customer demand for electricity and natural gas, driven by customer departures to CCAs, DA providers and legislative mandates to replace gas-fuel technologies, have on the Utility's ability to make and recover its investments through rates and earn its authorized ROE, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, and changing customer demand for its natural gas and electric services;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- the risks and uncertainties associated with the Utility's ability to accurately forecast major capital expenditures, weighted average annual rate base and expense reduction associated with implementation of the Lean operating system;

- the risks and uncertainties associated with rising rates for the Utility's customers;

- actions by credit rating agencies to downgrade PG&E Corporation's or the Utility's credit ratings;

- the severity, extent and duration of the global COVID-19 pandemic and its impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, as well as on energy demand in the Utility's service territory, the ability of the Utility to collect on customer receivables, the ability of the Utility to mitigate these effects, including with spending reductions, the ability of the Utility to recover any losses incurred in connection with the COVID-19 pandemic, and the impact of workforce disruptions caused either by illness of workers and their family members or workforce attrition related to potential new workplace regulations such as vaccine mandates;

- increased employee attrition as a result of the challenging political and operating environment facing PG&E Corporation and the Utility;

- whether PG&E Corporation's and the Utility's counterparties are available and able to meet their financial and performance obligations with respect to contracts, credit agreements, and financial instruments, which could be affected by disruptions in the global supply chain caused by the COVID-19 pandemic or otherwise; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained in Item 7. MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com, as promptly as practicable after they are filed with, or furnished to, the SEC. Additionally, PG&E Corporation and the Utility routinely provide links to the Utility's principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the "Regulatory Filings" tab, so that such filings are available to investors upon filing with the relevant agency. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "Chapter 11," "Wildfire and Safety Updates" and "News & Events: Events & Presentations" tabs, respectively, in order to publicly disseminate such information. Specifically, within two hours during business hours or four hours outside of business hours of the determination that an incident is attributable or allegedly attributable to the Utility's electric facilities and has resulted in property damage estimated to exceed $50,000, a fatality or injury requiring overnight in-patient hospitalization, or significant public or media attention, the Utility is required to submit an electric incident report including information about such incident. The information included in an electric incident report is limited and may not include important information about the facts and circumstances about the incident due to the limited scope of the reporting requirements and timing of the report and is necessarily limited to information to which the Utility has access at the time of the report. Ignitions are also reportable under CPUC Decision 14-02-015 when they involve self-propagating fire of material other than electrical or communication facilities; the fire traveled greater than one linear meter from the ignition point; and the Utility has knowledge that the fire occurred. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on such website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link.

PART I

ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in Northern and Central California. The Utility was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility's service area is shown in the graphic below.

PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found below in Item 8. Financial Statements and Supplementary Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Utility. Each of PG&E Corporation and the Utility is a separate entity, with distinct creditors and claimants, and is subject to separate laws, rules, and regulations.

Over the past several years, Northern California has experienced major wildfires. For more information about material wildfires, see Item 7. MD&A, and Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

This 2021 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, liquidity, and cash flows, see Item 1A. Risk Factors and "Forward-Looking Statements" above.

Triple Bottom Line

PG&E Corporation's and the Utility's purpose is to deliver for their hometowns, serve the planet, and lead with love. In support of this purpose, the companies employ a Lean operating model designed to drive more effective and responsive decision-making, reduce the human struggle many coworkers face in their day-to-day work, and deliver better outcomes for customers and communities.

PG&E Corporation and the Utility measure their progress toward the purpose by considering their impact on the "triple bottom line" of people, planet, and prosperity, which is underpinned by performance; this consideration takes into account not only the economic value they create for customers and investors, but also their responsibility to social and environmental goals. The triple bottom line is designed to balance the interests of the companies' many stakeholders, and it reflects the broader societal impacts of the companies' activities.

PG&E Corporation and the Utility will continue to consider the impact on the triple bottom line of people, planet, and prosperity in their daily operations as well as in their long-term strategic decisions. The Utility will continue to seek fair and timely regulatory treatment in order to support its customer-driven investment plan while pursuing cost-control measures that would allow it to maintain the affordability of its service. The Lean operating system is an important means of realizing PG&E Corporation's and the Utility's objective of achieving world class performance while delivering hometown service.

People

The people element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to their workforce, their customers, the residents of local communities in which the companies do business, and other stakeholders.

PG&E Corporation's and the Utility's goal is to continually reduce risk to keep customers, the communities they serve, and their workforce (both employees and contractors) safe. Their focus is on continuously building an organization where every work activity is designed to facilitate safe performance, every worker knows and practices safe behaviors, and every individual is encouraged to speak up and stop work if they see unsafe or risky behavior, and has confidence that their concerns and ideas will be heard and pursued. PG&E Corporation and the Utility are committed to significantly improving their safety performance by understanding their risks, prioritizing their work, using controls to reduce risks, and continuously measuring and improving risk reduction.

PG&E Corporation's and the Utility's human capital resource objectives are to build and retain an engaged, well trained, diverse, and equitable workforce. PG&E Corporation and the Utility place a high priority on delivering customer value and providing a hometown customer experience. The Utility's customer-driven investment program is aimed at improving safety, increasing electric and gas reliability, and improving customer satisfaction.

For more information, see "Human Capital" below.

Planet

The planet element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to protect and serve the environment. This commitment extends beyond compliance with various state and federal environmental, health, and safety laws and regulations. Management believes that integrating and managing climate change and other environmental considerations in the companies' business strategies creates long-term value for PG&E Corporation and the Utility, and for their customers, communities, coworkers, and other stakeholders. Mitigating and adapting to the impacts of climate change presents opportunities for growth for the Utility's business and economic opportunity for the communities it serves.

The Utility strives to be prepared to continue to deliver safe, clean, affordable, and reliable energy in the face of increasingly severe and extreme climate-driven natural hazards. To build resilience to these hazards, the Utility is working to systematically integrate the consideration of forward-looking climate data and tools in its decision-making. PG&E Corporation and the Utility also work with policymakers and regulators to advance effective climate adaptation policy in California, and work directly with local governments and communities on adaptation solutions.

PG&E Corporation and the Utility are an important enabler of California's effort to reduce GHG emissions. California has set a goal to achieve economy-wide carbon neutrality no later than 2045. SB 100 increased California's RPS target to 60% by the end of 2030 and requires 100% of retail sales to come from eligible renewables or zero-carbon resources by the end of 2045.

The impacts of climate change on the Utility's infrastructure are already a reality. Record-breaking extreme heat and heat waves are increasingly a regular occurrence throughout California. Peak loads are expected to increase with increasing temperatures due to direct impacts of ambient temperatures on equipment and direct impacts on electricity demand driven by rising air conditioning installation and usage. The Utility's assets on the coast and in or near watersheds face potential increased exposures to coastal, riverine, and precipitation-related flooding because of climate-driven changes in precipitation and sea-level rise.

Climate change will also continue to intensify the potential for wildfires throughout California. The worsening conditions across California increase the likelihood and severity of wildfires, including those where the Utility's equipment may be alleged to be associated with the fire's ignition. Reducing risk will be even more important as climate change continues to exacerbate the risks facing the Utility. A key element of preparing the Utility for the physical risks of climate change is a system-wide CVA of the Utility's assets, operations, and services, which the Utility expects to file with the CPUC in 2024. The CVA is expected to improve the Utility's understanding of its exposure to climate hazards and the sensitivity of assets and operations to these hazards.

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California utilities also are experiencing increasing deployment by customers and third parties of distributed energy resources, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and load management technologies. These developments will require sustained investments in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, and EV infrastructure. To this end, the CPUC is conducting proceedings to evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of distributed energy resources and consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by distributed energy resources, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator.

PG&E Corporation and the Utility continue to pursue policies and programs that enable safe, reliable, and affordable clean and resilient energy for their customers. As a result of actions already taken by PG&E Corporation and the Utility, the companies have:

- Exceeded California's renewable portfolio standards goal for each utility (including the Utility) to deliver 33 percent of eligible renewable energy by the end of 2020, and delivered clean electricity to customers in 2021 that was more than 90% GHG free.

- Helped customers avoid emissions through energy efficiency programs, supporting California's goal to double energy efficiency in existing buildings by 2030.

- Awarded contracts for more than 1.7 GWs of battery energy storage, strengthening California's grid efficiency and reliability.

- Installed approximately 5,000 charging ports for EVs at workplaces and multi-family dwellings, including installing 39% of these charging ports in disadvantaged communities, and also offered programs to support medium- and heavy-duty fleets and public fast charging in support of California's goal of 100 percent sales of light-duty zero-emission vehicles by 2035.

- Brought the total number of interconnected private solar customers to more than 600,000 and supported more than 33,000 customers who have installed battery storage at their homes or businesses.

- Pursued decarbonization initiatives for the Utility's natural gas delivery system, including working to interconnect several renewable natural gas projects.

Looking ahead, the Utility expects its GHG-free energy supply mix of renewable, large hydroelectric, and nuclear generation resources to remain elevated while Diablo Canyon continues to operate. Once Diablo Canyon ceases operations in 2025, the Utility expects its percentage of GHG-free electricity to decrease substantially. The CPUC coordinates the planning of supply resources through the Integrated Resource Planning ("IRP") proceeding and has determined that replacing the power generated by Diablo Canyon is the responsibility of all LSEs within the CAISO. Towards the end of the decade and beyond, the Utility's GHG-free energy supply mix is expected to grow relative to 2025 levels as the Utility works to meet California's IRP GHG emissions reduction targets and its RPS target. For more information, see "Integrated Resource Planning Procurement" below.

Prosperity

The prosperity element of the triple bottom line represents PG&E Corporation's and the Utility's commitment to meeting their financial objectives and providing economic development opportunities and benefits in the communities they serve. Management believes clean energy should be affordable for and inclusive of all economic backgrounds.

The Utility operates under a "cost of service ratemaking model," which means that rates for electric and natural gas utility services are generally set at levels that are intended to allow the Utility to recover its costs of providing service and have the opportunity to earn a return on invested capital. Under cost of service ratemaking, a utility's earnings depend on the outcomes of its ratemaking proceedings and its ability to manage costs.

In order to set rates, the CPUC and the FERC conduct proceedings to determine the amount that the Utility will be authorized to collect from its customers ("revenue requirements"). Revenue authorized by the CPUC through GRC proceedings is intended to provide the Utility a reasonable opportunity to recover its costs and earn a return on its investments in generation and distribution assets and general plant (also referred to as "rate base") on a forecast basis. The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, taxes, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A), including its costs to procure electricity and natural gas for customers and to administer public purpose and customer programs.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. The rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume through certain regulatory balancing accounts, or revenue adjustment mechanisms, that are designed to allow the Utility to collect its authorized base revenue requirements regardless of sales volume. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from, for example, weather or economic conditions. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

See "Ratemaking Mechanisms" below and "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC and FERC proceedings.

Generally, differences between forecast costs and actual costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations in Item 7. MD&A) can occur for numerous reasons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. The Utility has initiated a program to reduce its spending on operations and maintenance.

PG&E Corporation and the Utility are committed to taking steps to improve their credit ratings and metrics over time, including by reducing their debt. PG&E Corporation and the Utility have set goals to reduce their debt over time, including reducing PG&E Corporation's debt by $2 billion by the end of 2023. PG&E Corporation and the Utility expect that reducing the consolidated debt will help them achieve investment grade credit ratings for their unsecured securities, for the benefit of both customers and investors. For more information, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8. Additionally, the Utility filed an application with the CPUC seeking authorization for a post-emergence transaction to recover $7.5 billion of 2017 wildfire claims costs. Among other uses, as a result of the proposed transaction, the Utility would retire $6.0 billion of Utility debt. For more information, see "Application for Post-Emergence Securitization Transaction" in Item 7. MD&A.

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, as well as the Utility's preferred stock. PG&E Corporation's and the Utility's ability to issue dividends is subject to restrictions. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock. For more information, see "Dividends" in Item 7. MD&A.

Total capital expenditures (including accruals) recorded in 2021 were $8.6 billion. The Utility's total capital expenditures (including accruals) are forecasted to be between $7.8 billion and $8.9 billion for 2022, between $7.9 billion and $10.4 billion for 2023, between $7.9 billion and $10.7 billion for 2024, between $8.0 billion and $11.3 billion for 2025, and between $8.1 billion and $12.0 billion for 2026. The completion of projects, the timing of expenditures, and the associated cost recovery may be affected by permitting requirements and delays, construction schedules, availability of labor, equipment and materials, financing, legal and regulatory approvals and developments, community requests or protests, weather and other unforeseen conditions.

The Utility expects to make additional CPUC capital expenditures, the recovery of which will be subject to future regulatory approval, including the 2023 GRC. These expenditures include capital expenditures exceeding amounts authorized in the 2020 GRC, and expenditures to be included in a later stage of the 2023 GRC. The 2023 through 2026 currently above authorized capital spending levels are primarily for additional wildfire mitigation, transportation electrification and the Lakeside Building. Additionally, $3.21 billion of fire risk mitigation capital expenditures will be excluded from the Utility's equity rate base pursuant to AB 1054.

PG&E Corporation and the Utility are committed to keeping gas and electric services affordable for all customers. The Utility's capital investment plan, increasing procurement of renewable power and energy storage, increasing environmental regulations, and the cumulative impact of other public policy requirements collectively place continuing upward pressure on customer rates. Certain CPUC proceedings, such as the OIR to Revisit Net Energy Metering Tariffs, could impact different types of customers differently. Similarly, although the Utility generally recovers its electricity and natural gas procurement costs through rates as "pass-through" costs, commodity prices rose substantially in 2021, relative to 2020. The Utility is addressing this customer rate pressure with cost reductions through increased efficiency, including efficiency driven by implementing the Lean operating system, improving its work management, identifying additional opportunities to convert expenses to capital expenditures, and an improved organizational design. The Utility has a number of programs in place to assist low-income customers, such as the CARE program. Under the CARE program, income-qualified customers can receive a monthly discount of 20% or more on their gas and electric bill.

PG&E Corporation's and the Utility's Corporate Sustainability Report, which is available to the public, describes the companies' progress toward world-class performance measured with the triple bottom line framework.

In 2020, the Utility spent $3.9 billion with certified diverse suppliers, representing 38.9% of its total spend.

Performance: Underpinning The Triple Bottom Line

PG&E Corporation and the Utility are transitioning to the Lean operating system, which includes four basic "plays": visual management, operating reviews, problem solving and standard work. PG&E Corporation and the Utility have implemented the first two plays in 2021 and expect to roll out the second two plays in 2022. Visual management allows teams to see how they are performing against their most important metrics using real-time data. During 2021, PG&E Corporation and the Utility have set up over 2,000 daily operating reviews, beginning with crews closest to the work and cascading up to senior leadership. These brief meetings help the Utility identify gaps and quickly develop plans to support the teams performing the work and give the Utility more visibility, control and predictability in its operations. For instance, the Lean operating system helped the Utility identify patterns in the conditions of ignitions and led to the implementation of EPSS. PG&E Corporation's and the Utility's performance is also driven by an increased focus on alignment on shared outcomes among its leadership and within the organization.

PG&E Corporation and the Utility have implemented a regional operating model to place more co-workers and operational leadership closer to their customers. The purposes of regionalization are to address local issues faster; reduce outage response times; create faster interconnections for customers connecting solar or distributed energy to the grid; and build stronger relationships and information flow between the companies and their customers.

California has experienced unprecedented weather conditions in recent years and the Utility's service territory remains susceptible to additional wildfire activity. In response, the Utility has implemented operational changes and investments that reduce wildfire risk, including:

- *Enhanced Powerline Safety Settings:* In 2021, the Utility implemented the EPSS program, which adjusts the sensitivity of circuit protection devices on certain power lines to de-energize them more rapidly in the event of a disturbance to help prevent potential ignitions. After EPSS was initiated, CPUC-reportable ignitions were reduced substantially on EPSS-enabled circuits, compared to the prior three-year average.

- *Public Safety Power Shutoffs:* The PSPS program proactively de-energizes power lines in response to forecasted weather conditions. Since its inception in late 2017, the PSPS program has become more targeted because the Utility has developed more granular risk models, including adding consideration of vegetation management and maintenance tag statuses for scoping PSPS events. The Utility has also installed sectionalizers for more strategic de-energizations of circuits and transmission lines.

- *Vegetation management:* The Utility inspects its overhead electric distribution and transmission facilities on an annual basis to identify and clear vegetation that might grow or fall into utility equipment. In addition, the Utility operates an EVM program for distribution facilities in HFTD areas. The Utility is also increasing oversight and engagement with the contractors supporting vegetation management work.

- *Asset inspections:* Since 2018, the Utility has reoriented its asset inspections programs toward asset condition and consequence risk, particularly wildfire risk, and have become more thorough, standardized, digitized, and verifiable. The Utility uses risk-informed inspection cycles. In 2021, the Utility continued to refine its risk modeling, including further incorporating data from asset inspections.

- *System hardening:* System hardening entails replacing or eliminating existing distribution lines in HFTDs and installing stronger and more resilient equipment. Hardening methods include replacing bare overhead conductor with covered conductor and installing stronger poles, removing the line and serving our customers through remote grids, or converting the line from overhead to underground. In 2021, the Utility announced a commitment to underground 10,000 miles of electric distribution lines in HFTDs, which will eliminate ignition risks from overhead vegetation or wind-induced equipment failures in those areas and help reduce the need for vegetation management.

Even as the Utility works to mitigate wildfire risk, it also works to reduce the impact of those mitigations on its customers, including making the PSPS program less disruptive through sectionalizing devices for both distribution and transmission lines, temporary generation applications, and implementation of microgrid pilot technologies. For example, in 2021, the CPUC authorized the Utility to prepare 10 substations to form microgrids in the event of PSPS outages impacting the transmission lines feeding those substations, in addition to nine other distribution microgrids that the Utility made ready to operate in 2021. Two of the distribution microgrids piloted battery storage and a linear generator in a hybrid configuration with diesel generation to assist in energizing the microgrids when needed. Through these and other mitigation actions, PSPS events in 2021 impacted 78% fewer customers on average than PSPS events in 2019. The Utility also brought online its first “remote grid” in 2021, which allows distribution lines in HFTDs to be removed and replaced with locally sited resources. Remote grids can reduce costs and fire risks, while maintaining service to impacted customers. The Utility is pursuing the development of additional remote grid projects.

In 2021, the Utility also worked to reduce the impact of EPSS by adjusting the sensitivity of devices to reduce the likelihood of an outage, improving coordination between its devices to reduce the size of outages, and improving internal coordination of patrol crews for faster restoration times. In 2022, the Utility plans to expand the scope of the EPSS program to all HFTD areas.

The Utility has focused on continuously improving its gas operations safety record. Since the San Bruno natural gas pipeline explosion in 2010, the Utility’s asset safety efforts have included replacing distribution mains and transmission pipelines, as well as strength testing transmission pipelines. The Utility uses in-line inspections to assess the integrity of transmission pipelines. The Utility also uses safety and control systems to monitor, gather, and process real-time data on its gas system. In 2021, the Utility’s gas operations achieved zero workforce serious injuries and fatalities (“SIF-A”) incidents and reductions in the number of injuries that result in days away, restricted or transferred duty per 200,000 hours worked (“DART”). As of the date of this filing, the Utility’s gas system has not had a public safety-related incident that resulted in a fatality or injury since 2015 or 2018, respectively.

The Utility has engaged in educating employees, contractors, and the public regarding safe digging programs and practices for their awareness during construction and when digging near the Utility’s underground gas and electric assets. The Utility also installed safety devices that automatically detect increasing pressure on systems and stop the flow of gas to avoid outages and overpressure events. Additionally, the Utility continues to streamline its efforts to respond to outages timely. The Utility’s outage response is designed to keep the public safe while limiting customer outages and returning service safely and as quickly as possible.

The Utility’s generation operations have focused on safety and reliability. In 2021, the Utility’s generation operations achieved zero SIF-A incidents and reductions in DART. Challenged by a drought year, the Utility scheduled dispatch and rescheduled outages to maximize availability during the summer months when demand for electricity is highest. The Utility is working to implement a comprehensive generation asset management strategy and further mature its outage and project management capabilities.

Regulatory Environment

The Utility’s business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is regulated primarily by the CPUC. At the federal level, the Utility is regulated primarily by the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies, including with respect to safety, the environment, and health, such as the NTSB and OEIS.

This section and the “Environmental Regulation” and the “Ratemaking Mechanisms” sections below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. For more information, see Item 1A. Risk Factors and “Regulatory Matters” in Item 7. MD&A.

PG&E Corporation is a "public utility holding company" as defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

California Public Utilities Commission

The CPUC is a regulatory agency that regulates privately owned public utilities in California. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transmission and storage services. The CPUC also has exercised jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electric and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $100,000 per day, per violation. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and electric citation programs adopted by the CPUC in September 2016, the SED has discretion whether to issue a penalty for each violation; but if it assesses a penalty for a violation, it has the authority to impose the maximum statutory penalty of $100,000 per day, with an administrative limit of $8 million per citation issued. Similar to penalties imposed by the CPUC, penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders of an issuer and may not be recovered in rates or otherwise directly or indirectly charged to customers. The CPUC has also authorized the SED to propose for CPUC approval administrative consent orders and administrative enforcement orders when the SED deems a formal OII unnecessary.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to wildfires and wildfire cost recovery, increasing renewable energy resources, the development and widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the establishment of energy storage procurement targets, and the development of a state-wide EV charging infrastructure. The CPUC is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility's accounting, performance, and compliance with regulatory guidelines.

The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation's Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. For more information on specific CPUC enforcement matters and CPUC-implemented laws and policies and the related impact on PG&E Corporation and the Utility, see Item 1A. Risk Factors, and "Enforcement and Litigation Matters," "Regulatory Matters," "Legislative and Regulatory Initiatives" and "Liquidity and Financial Resources" in Item 7. MD&A and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Federal Energy Regulatory Commission and California Independent System Operator Corporation

The FERC has jurisdiction over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility's transmission systems with other electric systems and generation facilities, the tariffs and conditions of service of regional transmission organizations, and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliability of the nation's electric transmission grid, including standards to protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. The FERC's approval is also required under Federal Power Act Section 203 before undertaking certain transactions, including most mergers and consolidations, certain transactions that result in a change in control of a utility, purchases of utility securities and dispositions of utility property. The FERC has authority to impose fines of up to $1 million per day for violations of certain federal statutes and regulations. For more information on specific FERC requirements and their impact on PG&E Corporation and the Utility, see Item 1A. Risk Factors, and "Regulatory Matters," "Legislative and Regulatory Initiatives" and "Liquidity and Financial Resources" in Item 7. MD&A and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

The CAISO is the FERC-approved regional transmission organization for the Utility's service territory. The CAISO controls the operation of the electric transmission system in California and provides open access transmission service on a non-discriminatory basis. The CAISO is also responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, ensuring that the reliability of the transmission system is maintained, and operating an interstate energy imbalance market.

Nuclear Regulatory Commission

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. See "Electricity Resources" below. NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. For more information about Diablo Canyon, see Item 1A. Risk Factors and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Other Regulators

The California Energy Commission is California's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans and for adopting building and appliance energy efficiency requirements.

The CARB is the state agency responsible for setting and monitoring GHG and other emission limits. The CARB is also responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. See "Environmental Regulation - Air Quality and Climate Change" below.

The NTSB is an independent U.S. government investigative agency responsible for civil transportation accident investigations, including pipeline accidents. The NTSB also conducts special investigations and safety studies, and issues safety recommendations to prevent future accidents.

The California Geologic Energy Management Division is the state agency responsible for establishing and enforcing regulations for the operation of the Utility's underground gas storage wells.

The OEIS is a state agency responsible for reviewing and approving the Utility's WMP and for evaluating the Utility's implementation of the WMP.

In addition, the Utility obtains permits, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also periodically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy or use public property for the operation of the Utility's business and to conduct certain related operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highways. In exchange for the right to use public streets and highways, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. For more information see Item 1A. Risk Factors.

Third-party Monitors

On April 12, 2017, the Utility retained the Monitor at the Utility's expense as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, which sentenced the Utility to, among other things, a five-year corporate probation period and oversight by the Monitor for a period of five years. On January 25, 2022, the period of probation expired and the Monitor's oversight of the Utility ended. For more information see Item 1A. Risk Factors and "US District Court Matters and Probation" under "Enforcement and Litigation Matters" in Item 7. MD&A.

Additionally, as a condition to its approval of the Plan, the CPUC required the appointment of an independent safety monitor (the "Independent Safety Monitor") for a term of five years, subject to extension if the CPUC determines that the Utility's safety conditions would benefit from an Independent Safety Monitor's continued involvement. On January 28, 2022, the CPUC announced that it had selected Filsinger Energy Partners to serve as the Independent Safety Monitor. According to the scope of work authorized by the CPUC, the Independent Safety Monitor will (1) monitor and alert CPUC staff whether the Utility is implementing its highest priority and risk-driven safety mitigations and (2) monitor the Utility's safety-related recordkeeping and record management systems. In addition to confidential updates to the CPUC staff regarding safety-related concerns, the Independent Safety Monitor will also provide public summary reports of its activities to the CPUC every six months.

Material Effects of Compliance with Governmental Regulations

As indicated above, the Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. Compliance with such extensive government regulations requires substantial expenditures and has had in the past and may continue to have in the future a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, cash flows and competitive position. Generally, the Utility expects to recover the cost of compliance with government regulations through rates in its GRC proceedings, or other proceedings. To the extent the Utility incurs costs above authorized or incurs additional types of costs not included in rates, the Utility would expect to apply for recovery of such costs. Such recovery would be subject to the CPUC's approval and could involve its reasonableness review.

Costs incurred in 2021 included costs in connection with upgrading and maintaining the Utility's electric and natural gas infrastructure in accordance with CPUC and federal requirements, participating in the Wildfire Fund under AB 1054, execution of wildfire mitigation initiatives, the licensing and other regulations of the FERC, environmental regulations, clean energy standards, regulations regarding Diablo Canyon, and various other generation, distribution and storage regulations, the amount of which was substantial.

If the Utility is unable to recover these costs or incurs fines or penalties as a result of non-compliance with such laws and regulations, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, cash flows and competitive position could be materially impacted. For more information, see Item 1A. Risk Factors, "Regulatory Matters" in Item 7. MD&A, and Notes 14 and 15 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental Regulation

The Utility's operations are subject to extensive federal, state, and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the reporting and reduction of CO_2 and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, including endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. See Item 1A. Risk Factors. Generally, the Utility recovers most of the costs of complying with environmental laws and regulations through the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to various regulations adopted by the EPA, including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended. The Utility is also subject to the regulations adopted by other federal agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act, these persons (known as "potentially responsible parties") may be jointly and severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these federal, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overseen by the California DTSC, several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former MGP sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley and Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Air Quality and Climate Change

The Utility's electric generation plants, natural gas pipeline operations, vehicle fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter, and other emissions.

Federal Regulation

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

Tackling the climate crisis is a key priority of the Biden Administration, and the Administration has signaled its intent to use its executive and regulatory authorities to reduce emissions in line with science-based targets. On January 20, 2021, President Biden issued an EO directing the EPA to consider suspending, revising or rescinding the Trump Administration's rule for methane emissions from new sources in the oil and gas sector and propose a companion regulation for existing sources, including the transmission, processing and storage segments of the industry. For power plants, the EPA is expected to propose a more stringent GHG standard for existing sources in the wake of challenges to the Trump Administration's Affordable Clean Energy rule.

State Regulation

California's AB 32, the Global Warming Solutions Act of 2006, provided for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target, including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program that sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy.

The cap-and-trade program's first compliance period, which began on January 1, 2013, applied to the electric generation and large industrial sectors. In the subsequent compliance period, which began on January 1, 2015, the scope of the regulation was expanded to include the natural gas and transportation sectors, effectively covering all of the state economy's major sectors through 2020. The Utility's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than large natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation.

In 2017, AB 398 extended the cap-and-trade program through January 1, 2031. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Entities with a compliance obligation can obtain allowances from the CARB at quarterly auctions or from third parties or exchanges. Complying entities may also satisfy a portion of their compliance obligation through the purchase of offset credits (e.g., credits for GHG reductions achieved by third parties, such as landowners, livestock owners, and farmers, that occur outside of the entities' facilities through CARB-qualified offset projects such as reforestation or biomass projects). The Utility expects all costs and revenues associated with the GHG cap-and-trade program to be passed through to customers.

SB 32 (2016) requires that CARB ensure a 40% reduction in GHGs by 2030 compared to 1990 levels. The California RPS program that requires utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California. In September 2018, SB 100 was signed into law, which accelerated California's 50% RPS target to December 31, 2026, increased the RPS target to 60% by December 31, 2030, and further amended the RPS statute to set a policy of meeting 100% of retail sales from eligible renewables and zero-carbon resources by December 31, 2045. Additionally, EO B-55-18 set a statewide goal to achieve economy-wide carbon neutrality by 2045 and to maintain net negative emissions thereafter. The Utility will be an active participant in regulatory proceedings to determine how the state will achieve carbon neutrality. For the percentage of the Utility's estimated total net deliveries of electricity to customers in 2021, including estimated GHG-free and renewable energy percentages, see "Electric Utility Operations-Electricity Resources" below.

Climate Change Resilience Strategies

During 2021, the Utility continued its programs to mitigate the impact of the Utility's operations (including customer energy usage) on the environment and to take actions to increase its resilience to the physical impacts of climate change on the Utility's operations. The Utility regularly reviews the most relevant scientific literature on climate change such as rising sea levels, major storm events, increasing temperatures and heatwaves, wildfires, drought and land subsidence, to help the Utility identify and evaluate climate change-related risks and develop resilience strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including wildfires, extreme storms, and heat waves and considers climate hazards in its risk-assessment process to account for long-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

The Utility is continuing its work to better understand the current and future impacts of climate change. Climate change is incorporated into the Utility's Risk Assessment Mitigation Phase ("RAMP") filing, which describes its quantitative risk modeling process and major risks. The Utility also considers the RAMP analysis in developing its infrastructure investment plans. Additionally, the Utility is conducting a system-wide CVA focused on 2050 to identify and help prioritize the Utility's climate-driven hazards. Concurrent with the CVA are efforts to align key processes with the best available climate projections. For example, the Utility is currently reviewing and updating equipment design standards that rely on historically observed heat thresholds, which are not expected to be predictive of future temperatures.

With respect to electric operations, climate scientists project that climate change will lead to increased electricity demand due to more extreme and frequent hot weather. The Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage will help it adapt to the expected changes in demand for electricity. The Utility is making substantial investments to build a more resilient system that can better withstand extreme weather and related emergencies. For more information on such investments, see "Performance: Underpinning The Triple Bottom Line" above. Over the long term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to projected sea level rise combined with high tides, storm runoff and storm surges. Inland areas, such as near the Sacramento-San Joaquin River Delta, will also be vulnerable to flooding amid changes to precipitation patterns and extreme storms. As the state continues to face increased risk of wildfires, the Utility's wildfire mitigation activities, including vegetation management and undergrounding electric powerlines, will continue to play an important role to help reduce the risk of wildfire and its impact on electric and gas facilities.

Climate scientists predict that climate change will result in rising temperatures and changes in precipitation patterns in the Utility's service territory, including decreasing snowpack. This could, in turn, affect the Utility's hydroelectric generation. This issue is being analyzed as part of the Utility's CVA. To plan for this change, the Utility is engaging with state and local stakeholders and is also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testing and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and volume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials. The Utility is also actively engaged with renewable natural gas producers to facilitate supply interconnections with the Utility's natural gas pipeline system and is participating in CPUC proceedings that evaluate standards to allow for the injection of hydrogen into natural gas systems and decarbonization through electrification.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2020, which is the most recent data available, totaled more than 44 million metric tons of CO_2 equivalent, the majority of which came from customer natural gas use. The following table shows the 2020 GHG emissions data the Utility reported to the CARB under AB 32, which is the most recent data available. PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Sustainability Report.

Source	Amount (metric tons CO_2 equivalent)
Fossil Fuel-Fired Plants [(1)]	2,550,622
Natural Gas Compressor Stations and Storage Facilities [(2)]	315,802
Distribution Fugitive Natural Gas Emissions	497,512
Customer Natural Gas Use [(3)]	40,304,583

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations.
(2) Includes emissions from compressor stations and storage facilities that are reportable to CARB.
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural gas local distribution companies.

The Utility utilized the CEC's Power Source Disclosure program methodology to calculate the CO_2 emissions rate associated with the electricity delivered to retail customers in 2020. This resulted in a third-party verified CO_2 emissions rate of 160 pounds of CO_2 per MWh.

Air Emissions Data for Utility-Owned Generation

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Sustainability Report.

	2020	2019
Total NOx Emissions (tons)	141	135
NOx Emissions Rate (pounds/MWh)	0.01	0.01
Total SO_2 Emissions (tons)	15	14
SO_2 Emissions Rate (pounds/MWh)	0.001	0.001

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humboldt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and other nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice and the Utility executed a settlement agreement that provided a claims process by which the Utility submits annual requests for reimbursement of its ongoing spent fuel storage costs. The claim for the period June 1, 2020 through May 31, 2021, totaled approximately $11.6 million and is currently under review by the DOE. Amounts reimbursed by DOE are refunded to customers through rates. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

Ratemaking Mechanisms

The Utility's rates for electric and natural gas utility services are generally set at levels that are intended to allow the Utility to recover its costs of providing service and a return on invested capital ("cost-of-service ratemaking"). In order to set rates, the CPUC and the FERC conduct proceedings to determine the amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The Utility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses (e.g., maintenance, administration and general expenses) and capital costs (e.g., depreciation, and financing expenses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A), including its costs to procure electricity and natural gas for customers and to administer public purpose and customer programs.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings. The rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume through certain regulatory balancing accounts, or revenue adjustment mechanisms, that are designed to allow the Utility to collect its authorized base revenue requirements regardless of sales volume. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from, for example, weather or economic conditions. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

Due to the seasonal nature of the Utility's business and rate design, customer electric bills are generally higher during summer months (May to October) because of higher demand, driven by air conditioning loads. Customer bills related to gas service are generally higher during winter months (November to March) because of higher demand due to heating.

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs.

See "Regulatory Matters" in Item 7. MD&A for more information on specific CPUC proceedings.

Base Revenues

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs related to its electric distribution, natural gas distribution, and Utility-owned electric generation operations and return on rate base. In the past, the CPUC has generally conducted a GRC every three years. Starting with the 2023 GRC, the CPUC will conduct a GRC every four years that includes the Utility's costs of its gas transmission and storage facilities. The CPUC approves the annual revenue requirements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally authorized for cost increases related to invested capital and inflation. Parties in the Utility's GRC include the Public Advocates Office of the CPUC (formerly known as Office of Ratepayer Advocates or ORA) and TURN, which generally represent the overall interests of residential customers, as well as numerous intervenors, that represent other business, community, customer, environmental, and union interests. For more information about the Utility's GRC, see "Regulatory Matters - 2020 General Rate Case" and "Regulatory Matters - 2023 General Rate Case" in Item 7. MD&A.

Cost of Capital Proceedings

The CPUC periodically conducts a cost of capital proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC's cost of capital proceedings generally take place in a consolidated proceeding with California's other large investor-owned electric and gas utilities. For more information about the cost of capital proceedings, see "Regulatory Matters - Cost of Capital Proceedings" in Item 7. MD&A.

Electricity Transmission Owner Rate Cases

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. In its TO rate cases, the Utility uses a formula rate methodology, which includes an authorized revenue requirement and rate base for a given year but also provides for an annual update of the following year's revenue requirement and rates in accordance with the terms of the FERC-approved formula. Under the formula rate mechanism, transmission revenue requirements are updated to the actual cost of service annually as part of the true-up process. Differences between amounts collected and determined under the formula rate are either collected from or refunded to customers. The FERC-approved formula rate will be effective through December 31, 2023. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and by the CAISO in its Transmission Access Charges to wholesale customers. For more information, see "Regulatory Matters - Transmission Owner Rate Cases" in Item 7. MD&A. The Utility also recovers a portion of its revenue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are charged individualized rates based on the terms of their contracts.

Program-Specific Memorandum Account and Balancing Account Costs

Periodically, costs arise outside of the CPUC GRC rate requests or that have been deliberately excluded therefrom. These costs may result from catastrophic events, changes in regulation, new programs, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed reasonable. For instance, these accounts allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. Recovery of the costs tracked in these memorandum accounts in rates requires CPUC authorization in separate proceedings for which the Utility may be unable to predict the outcome. Alternatively, the Utility may seek authority to track incremental costs related to these non-GRC programs in balancing accounts. The CPUC may authorize recovery of costs tracked in the balancing accounts on either a "one-way" basis, which only allows actual costs to be recovered up to a pre-established cap, or a "two-way" basis, which allows actual costs to be recovered, subject to CPUC review. For more information, see "Regulatory Matters - Cost Recovery Proceedings" in Item 7. MD&A and Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

Revenues to Recover Energy Procurement and Other Pass-Through Costs

Electricity Procurement Costs

California IOUs are responsible for procuring electrical capacity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electric contracts. The utilities are responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their BPPs based on long-term demand forecasts. In October 2015, the CPUC approved the Utility's most recent comprehensive BPP. It was revised since its initial approval and will remain in effect as revised until superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved BPPs without further after-the-fact reasonableness review by the CPUC. The CPUC may disallow costs associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to follow the principles of least-cost dispatch. Additionally, the CPUC may disallow the value of lost generation due to unplanned outages at utility-owned generation facilities.

The Utility recovers its electric procurement costs annually primarily through balancing accounts. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8. Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments, GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electric rates more frequently if the forecasted aggregate over-collections or under-collections in the Energy Resource Recovery Account, net of Portfolio Allocation Balancing Account balances, exceed five percent of its prior year electric procurement and Utility-owned generation revenues. The CPUC performs an annual compliance review of the procurement transactions recovered in various balancing accounts, including the Energy Resource Recovery Account and the Portfolio Allocation Balancing Account.

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved BPP, to meet mandatory renewable energy targets, and to comply with RA requirements. For more information, see "Electric Utility Operations - Electricity Resources" below as well as Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility is also responsible, as the central procurement entity ("CPE") for its distribution service area, for seeking to procure the entire amount of required local RA on behalf of all load serving entities in its distribution service area. The decision grants the Utility, acting as CPE, discretion to defer procurement of local resources to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high. The Utility, as the CPE, will not be assessed fines or penalties for failing to procure resources to meet the local RA requirements and deferring local procurement to the CAISO backstop mechanism, as long as the CPE exercised reasonable efforts to secure capacity and certain specified requirements are met. In connection with its CPE function, the Utility is responsible for making compliance demonstrations to the CPUC and the CAISO. The Utility recovers its administrative and procurement costs associated with its CPE function through a balancing account. Each year, the CPUC reviews the Utility's forecasted administrative costs related to the CPE function and approves a forecasted revenue requirement associated with the administrative costs. The CPUC performs an annual compliance review of the CPE function, including procurement transactions with terms of five years or less (for which costs incurred in compliance with certain prescribed criteria are deemed reasonable and pre-approved without further after-the-fact reasonableness review). Procurement transactions with terms exceeding five years are reviewed separately. The CPUC may disallow costs associated with the CPE function that were not incurred in compliance with the CPUC's decisions and guidance.

The CPUC has also approved the Power Charge Indifference Adjustment ("PCIA"). The PCIA is a cost recovery mechanism to ensure that customers who switch from the Utility's bundled service to a non-Utility provider, such as a DA or CCA provider, pay their share of the above market costs associated with long-term power purchase commitments and Utility-owned generation made on their behalf.

Natural Gas Procurement, Storage, and Transportation Costs

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electric rates.

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates, subject to limits as set forth in its CPIM described below. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate changes.

The CPIM protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for its core gas portfolio. Under the CPIM, the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered through rates. One-half of the costs above 102% of the benchmark are recoverable through rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of these savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by the FERC-approved tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers, including the Utility, pay for pipeline service, and the applicable Canadian tariffs are approved by the National Energy Board, a Canadian regulatory agency. The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas procurement costs or as a cost of electricity.

Costs Associated with Public Purpose and Customer Programs

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide discounted rates for specified types of customers, such as for low-income customers under the CARE program, which is paid for by the Utility's other customers.

Nuclear Decommissioning Costs

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities 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. Nuclear decommissioning costs are generally collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approval of the Utility's updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility's nuclear plants. If the nuclear decommissioning trusts are overfunded, the amount of such overfunding will be returned to customers. Pursuant to Public Utilities Code Section 8325, to the extent the monies available for decommissioning are insufficient to pay for all reasonable and prudent decommissioning costs, the CPUC must authorize the electric utility to collect these charges from its customers.

For costs related to AROs see "Nuclear Decommissioning Obligation" in Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

Human Capital

Employees and Contractors

As of December 31, 2021, PG&E Corporation and the Utility had approximately 26,000 regular employees, 11 of whom were employees of PG&E Corporation. Of the Utility's regular employees, approximately 16,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW") Local 1245; the Engineers and Scientists of California ("ESC") IFPTE 20; and the Service Employees International Union Local 24/7 ("SEIU"). The collective bargaining agreements currently in effect for the IBEW Local 1245 and ESC Local 20 will expire on December 31, 2025. The agreements increase wages annually by 3.75% from 2022 through 2025 and maintain current contributions to specified benefits. The IBEW and ESC represent approximately 62% of the Utility's employee workforce and support several areas of the Utility's business, including gas and electric operations. The term of the SEIU bargaining agreement ended on December 31, 2021. The parties have reached an agreement which is pending ratification by the SEIU. The Utility enjoys stable and productive relationships with its unions and did not experience any work stoppages in 2021.

PG&E Corporation's employees are primarily at the executive management level, which experienced significant employee turnover throughout the course of its Chapter 11 Cases in 2019 and 2020. The Utility generally has a stable workforce, which translated into low voluntary turnover during that period. The Utility's turnover rates for 2021 and 2020 were 5.8% and 4.7%, respectively. Approximately 41% of PG&E Corporation's and the Utility's employees have a tenure of more than 10 years, with an average tenure of 11 years. Currently, approximately 21% of PG&E Corporation's and the Utility's employees are eligible to retire. (PG&E Corporation and the Utility define retirement age as 55 years and older.)

The Utility's contractors and subcontractors include approximately 35,300 individuals from approximately 1,560 contractor companies.

Human Capital Management

PG&E Corporation's and the Utility's human capital resource objectives are to build and retain an engaged, well trained, diverse, and equitable workforce. PG&E Corporation's and the Utility's Boards of Directors are responsible for overseeing management's development and execution of PG&E Corporation's and the Utility's human capital strategy.

To build employee engagement, the Utility has a variety of both executive-level and employee-led initiatives and programs. PG&E Corporation's and the Utility's executive teams meet regularly to discuss and evaluate the state of employee talent, determine which programs are driving engagement and performance, and clarify the specific skills, behaviors, and values that should be cultivated. Each year, the Utility honors employees whose work embodies safety, diversity and inclusion, environmental leadership, and community service. The Utility conducts a biennial employee engagement survey, quarterly pulse surveys, and voluntary upward feedback surveys to measure and track employee engagement progress.

Every year, PG&E Corporation and the Utility offer or require technical, leadership, and employee training, which includes a range of technical training for employees on the knowledge and skills required to perform their jobs safely using approved tools and work procedures. In addition, employees are required to complete an annual compliance and ethics training and a Code of Conduct training, both of which are intended to promote a culture in which employees are encouraged to speak up with any concerns or ideas for continuous improvement. In addition, the Utility offers a variety of other trainings and education opportunities.

Among other programs, the Utility provides career opportunities through its Power Pathway™ workforce development program. Launched in 2008, PowerPathway is a workforce development model to enlarge the talent pool of local, qualified, diverse candidates for skilled craft and utility industry jobs through training program partnerships with educational, community-based and government organizations. PowerPathway helps people throughout the Utility service territory, including women and military veterans, prepare and compete for high demand jobs in the utility and energy industry. Students receive approximately eight weeks of industry-informed curriculum to ensure the academic, job specific, employability skills and physical training necessary to effectively compete for entry-level employment. Programs may also include hands-on training and on-the-job training.

PG&E Corporation and the Utility also provide integrated solutions and programs that cover employee health and wellness and that encompass physical, emotional, and financial health, including an on-site health clinic, an annual health screening, and health management tools and resources, in addition to more traditional programs.

PG&E Corporation's and the Utility's financial incentives offered to employees include a Short-Term Incentive Plan ("STIP"), an at-risk part of employee compensation designed to reward eligible employees for achieving specific performance goals. The 2021 STIP was focused on company objectives of safety, customer impact, and financial health.

All PG&E Corporation or Utility officer compensation currently is funded by shareholders.

Safety

The Utility has developed a five-year workforce safety strategy that includes two major pillars: systems and culture. Systems refers to risk management, equipment, processes and procedures. Culture refers to employee engagement, adherence to established requirements, a sense of urgency for safety, and leadership. Focus areas in the Utility's workplace safety strategy include: an enterprise safety management system, enhanced risk management, strengthening the contractor management program, improvement of safety technical standards, ergonomics, safety audits, improving data management and reporting systems, and enhancing safety leadership training. For employees and contractors performing medium- and high-risk work, the Utility's safety metrics include the number of SIF-A incidents and the SIF-P rate, which measures events that could have resulted in a SIF-A per 200,000 hours worked. In 2021, the Utility had five SIF-A events, which resulted in three fatalities and three serious injuries, and a SIF-P rate of 0.11, which was 10% higher than the SIF-P rate in 2020. The requirement for contractors to report SIF-P events was implemented in June 2020. Additionally, the Utility measures DART. In 2021, the Utility's DART was 1.01, which was 25% lower than in 2020 and its lowest rate in the past five years.

Throughout the COVID-19 pandemic, PG&E Corporation and the Utility have continued to monitor activities at the Centers for Disease Control and Prevention and the World Health Organization, PG&E Corporation and the Utility have updated their protocols and actions in accordance with guidance from these organizations, following state and local health and safety regulations, and in consultation with the Utility's medical director. PG&E Corporation and the Utility have also remained focused on protecting the health and safety of their employees, contractors and the Utility's customers, while continuing to perform critical utility work, and have continued to monitor and track the impact of the pandemic, modifying or adopting new policies in support of their employees' health and safety as pandemic conditions and governmental response have changed. For example, PG&E Corporation and the Utility have directed employees to work remotely from home where possible, implemented face coverings, physical distancing policies, and required a daily health check when an employee works outside his or her home, required virtual ergonomic evaluations to ensure that employees working from home so do safely and ergonomically, provided additional COVID-19 safety resources for employees who perform utility work in the field, and updated several of their employee benefits as a result of COVID-19, including healthcare benefits and interim time off and leave policies that support the care and new educational environment of children during the pandemic.

Diversity and Inclusion

PG&E Corporation's and the Utility's goal is to foster a diverse, equitable, and inclusive environment that enables all of their coworkers to bring their best selves to work so that they can provide exceptional customer service. These efforts are led by PG&E Corporation's and the Utility's Executive Vice President, People, Shared Services and Supply Chain, with support from the executive team. The People and Compensation Committee of PG&E Corporation's Board of Directors reviews the companies' diversity and inclusion practices and performance.

Key elements of PG&E Corporation's and the Utility's approach include active programming to heighten cultural competency, encourage understanding and appreciation of diversity, and integrate thoughtful content into training and performance support materials.

Additionally, the Utility's 11 Employee Resource Groups and three Engineering Network Groups execute enterprise-wide programming, certain coworkers lead efforts within their departments, and other specialized teams facilitate dialogue across the companies. These efforts foster employee belonging and support an environment of inclusion that values and respects diversity in the workforce.

In 2021, women, minorities, and military veterans accounted for approximately 27%, 48% and 7%, respectively, of total PG&E Corporation and Utility employees. Approximately 8% of the Utility's employees are younger than 30, 60% are between the ages of 30 and 49, and 32% are 50 or older.

Electric Utility Operations

The Utility generates electricity and provides electric transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides "bundled" services (i.e., electricity, transmission, and distribution services) to customers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations. For more information, see "Regulatory Matters" in Item 7. MD&A.

Electricity Resources

The Utility is required to maintain capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is responsible for scheduling and bidding electric generation resources, including certain electricity procured from third parties into the wholesale market, to meet customer demand.

The following table shows the percentage of the Utility's estimated total net deliveries of electricity to customers in 2021 represented by each major electric resource, and further discussed below. The Utility's deliveries were primarily from renewable energy resources that qualify under California's RPS and other GHG-free resources (i.e., nuclear, and large hydroelectric generation). California's RPS requirements and SB 100 goal to serve 100% of retail electricity sales with GHG-free resources by 2045 are discussed further below and in the Environmental Regulation section above.

The total estimated electricity generated, procured, and sold (net), as of December 31, 2021 was 33,149 GWh [(1)] and comprised of the following:

	Percent of Bundled Retail Sales (estimated procurement)	CEC Reporting Methodology Adjustment[(2)]	Percent of Bundled Retail Sales (estimated Power Content Label) [(2)]
Owned Generation Facilities			
Renewable [(3)]	2 %	— %	2 %
Nuclear	39 %	— %	39 %
Large Hydroelectric	4 %	— %	4 %
Fossil fuel-fired [(4)]	19 %	(15) %	4 %
Total	**64 %**	**(15)%**	**49 %**
Third-Party Purchase Agreements			
Renewable [(3)]	48 %	— %	48 %
Large Hydroelectric	— %	— %	— %
Fossil fuel-fired [(4)]	15 %	(12) %	3 %
Total	**63 %**	**(12)%**	**51 %**
Others, Net [(2)(5)]	**(27)%**	**27 %**	**— %**
TOTAL	**100 %**	**— %**	**100 %**
Total Renewable Energy Resources [(3)]	**50 %**	**— %**	**50 %**
GHG-Free Resources [(6)]	**93 %**	**— %**	**93 %**

(1) This amount excludes electricity provided by DA providers and CCAs that procure their own supplies of electricity for their respective customers.

(2) The allocation of "Others, Net" in the "CEC Reporting Methodology Reduction" and "Power Content Label" columns is consistent with CEC guidelines, applied to specified electric generation and procurement volumes (i.e., fossil fuel-fired, nuclear, large hydroelectric, and renewable). Total reported generation and procurement volumes equate to actual electric retail sales.

(3) Amounts include biopower (e.g., biogas, biomass), solar, wind, certain hydroelectric (i.e., 30MW or less), and geothermal facilities.

(4) Amounts consist primarily of natural gas facilities.

(5) Amount is mainly comprised of net CAISO open market (sales)/purchases.

(6) Amount is comprised of renewable, nuclear, and large hydroelectric facility resources generated, procured, and sold.

Renewable Energy Resources

California law established an RPS that requires LSEs, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers. SB 350 increased the amount of renewable energy that must be delivered by most LSEs, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period, and in each three-year compliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. In September 2018, the California Governor signed SB 100 into law, increasing from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and established state policy that 100% of all retail electricity sales must come from RPS-eligible or carbon-free resources by 2045. The Utility may in the future incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable through rates as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher renewable targets.

Renewable generation resources, for purposes of the RPS requirements, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. RPS requirements are based on procurement, which aligns with the methodology presented in the first column of the table above. Procurement from renewable energy sources was estimated as 50% in 2021.

The estimated total renewable deliveries as of December 31, 2021 shown above was 16,387 GWh and comprised of the following:

Type	Percent of Bundled Retail Sales (estimated procurement)[(1) (2)]
Biopower	4 %
Geothermal	5 %
RPS-Eligible Small Hydroelectric	2 %
Solar	28 %
Wind	11 %
Total	**50 %**

(1) Estimated renewable procurement amounts are expected to be consistent with Power Content Label reporting and adjustments, based on current CEC guidelines.

(2) Estimated renewable procurement percentages above and renewable compliance percentages are expected to be consistent; however, final RPS compliance reporting may result in some differences between the two percentages.

Energy Storage

Energy storage improves system reliability and supports California's decarbonization goals by integrating increased levels of renewable energy. The CPUC has established a multi-year energy storage procurement framework, under which the Utility was required to procure 580 MW of qualifying storage capacity by the end of 2020, with all energy storage projects required to be operational by the end of 2024. As of December 31, 2021, the Utility was on track to meet its storage goals by the end of 2024.

Additionally, the Utility has been actively procuring energy storage to meet critical reliability needs. The CPUC previously approved more than 1,100 MW of storage to come online in 2022 and 2023. In January 2022, the Utility also requested CPUC approval for another 1,600 MW of storage to be completed by the summer of 2024, which would bring the Utility's total energy storage system capacity to more than 3,330 MW. Finally, the Utility expects to solicit 200 MW of long-duration storage, which is storage with at least eight hours of discharge capacity, in 2022 to have these resources online between 2026 and 2028.

Owned Generation Facilities

At December 31, 2021, the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Nuclear [(1)]:			
Diablo Canyon	San Luis Obispo	2	2,240
Hydroelectric [(2)]:			
Conventional	16 counties in northern and central California	100	2,648
Helms pumped storage	Fresno	3	1,212
Fossil fuel-fired:			
Colusa Generating Station	Colusa	1	657
Gateway Generating Station	Contra Costa	1	580
Humboldt Bay Generating Station	Humboldt	10	163
Photovoltaic [(3)]:	Various	13	152
Total		**130**	**7,652**

(1) The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. On January 11, 2018, the CPUC approved the Utility's application to retire Unit 1 by 2024 and Unit 2 by 2025.
(2) The Utility's hydroelectric system consists of 103 generating units at 64 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to the FERC's licensing requirements), with license terms between 30 and 50 years.
(3) The Utility's large photovoltaic facilities are Cantua solar station (20 MW), Five Points solar station (15 MW), Gates solar station (20 MW), Giffen solar station (10 MW), Guernsey solar station (20 MW), Huron solar station (20 MW), Stroud solar station (20 MW), West Gates solar station (10 MW), and Westside solar station (15 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

Generation Resources from Third Parties

The Utility has entered into various agreements to purchase power and electric capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. See "Ratemaking Mechanisms" above. For more information regarding the Utility's power purchase agreements, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2021, the Utility owned approximately 18,000 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 33 electric transmission substations with a capacity of approximately 70,000 MVA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes many western states, the Canadian provinces of Alberta and British Columbia, and parts of Mexico.

Decisions about expansions and maintenance of the transmission system can be influenced by decisions of the Utility's regulators and the CAISO.

Electricity Distribution

The Utility's electric distribution network consists of approximately 108,000 circuit miles of distribution lines (of which, as of December 31, 2021, approximately 25% are underground and approximately 75% are overhead), 67 transmission switching substations, and 753 distribution substations with a capacity of approximately 35,000 MVA. The Utility's distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

These distribution substations serve as the central hubs for the Utility's electric distribution network. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity. The Utility operates electric distribution control center facilities in Concord, Rocklin, and Fresno, California; these control centers form a key part of the Utility's efforts to create a smarter, more resilient grid.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2019 to 2021 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 2021, 2020 or 2019.

	2021	2020	2019
Customers (average for the year)	5,539,969	5,498,044	5,457,101
Deliveries (in GWh) [1]	78,588	78,497	78,070
Revenues (in millions):			
Residential	$ 6,089	$ 5,523	$ 4,847
Commercial	5,042	4,722	4,756
Industrial	1,493	1,530	1,493
Agricultural	1,565	1,471	1,106
Public street and highway lighting	73	69	67
Other [2]	(84)	(130)	168
Subtotal	14,178	13,185	12,437
Regulatory balancing accounts [3]	953	673	303
Total operating revenues	**$ 15,131**	**$ 13,858**	**$ 12,740**
Selected Statistics:			
Average annual residential usage (kWh)	5,889	6,179	5,750
Average billed revenues per kWh:			
Residential	$ 0.2125	$ 0.1852	$ 0.1762
Commercial	0.1802	0.1730	0.1585
Industrial	0.1075	0.1085	0.1015
Agricultural	0.2104	0.2210	0.2172
Net plant investment per customer	$ 9,199	$ 8,889	$ 8,375

(1) These amounts include electricity provided by DA providers and CCAs that procure their own supplies of electricity for their respective customers.
(2) This activity is primarily related to provisions for rate refunds and unbilled electric revenue, partially offset by other miscellaneous revenue items.
(3) These amounts represent revenues authorized to be billed.

Natural Gas Utility Operations

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commercial, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e., natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as "core transport agents"). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 96% of core customers, representing approximately 85% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility generally does not provide procurement service to non-core customers, which must purchase their gas supplies from third-party suppliers, unless the customer is a natural gas-fired generation facility with which the Utility has a power purchase agreement that includes its generation fuel expense. The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and distinct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers (i.e., outside of the Utility's service territory) and to third-party natural gas storage customers.

Natural Gas Supplies

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have varied generally based on market conditions. During 2021, the Utility purchased approximately 302,000 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 43% of the total natural gas volume the Utility purchased during 2021.

Natural Gas System Assets

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 2021, the Utility's natural gas system consisted of approximately 43,800 miles of distribution pipelines, over 6,200 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. interconnecting downstream with TransCanada Foothills Pipe Lines Ltd., B.C. System. The Foothills system interconnects at the border to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport natural gas from the U.S. Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, Oregon, at the California border. Similarly, the Utility has a firm transportation agreement with Transwestern Pipeline Company, LLC to transport natural gas from supply points in the southwestern United States to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona. (For more information regarding the Utility's natural gas transportation agreements, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility owns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's gas transmission system. In 2019, the CPUC approved the discontinuation, through closure or sale, of operations at two of the Utility's owned and operated gas storage fields, Pleasant Creek and Los Medanos. The Utility expects to sell Pleasant Creek in 2022 in accordance with the CPUC's final decision in the 2019 GT&S rate case. The Utility intends to retain the Los Medanos field to further support system supply reliability as proposed in the 2023 GRC. The Utility owns and operates compressors and other facilities at these storage fields that are used to inject gas into the fields for storage and later for withdrawal. In addition, four independent storage operators are interconnected to the Utility's Northern California gas transmission system.

In 2021, the Utility continued upgrading transmission pipeline to allow for the use of in-line inspection tools and continued its work on the final recommendation from the NTSB's 2010-11 San Bruno investigation to hydrostatically test all high consequence pipeline mileage. The Utility currently plans to complete this NTSB recommendation by 2022 for remaining short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2019 through 2021 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 2021, 2020 or 2019.

	2021	2020	2019
Customers (average for the year) [(1)]	4,563,747	4,545,700	4,518,209
Gas purchased (MMcf)	226,037	226,746	227,621
Average price of natural gas purchased	$ 3.19	$ 2.02	$ 2.08
Bundled gas sales (MMcf):			
Residential	162,205	162,682	162,876
Commercial	54,262	49,834	54,479
Total Bundled Gas Sales	**216,467**	**212,516**	**217,355**
Revenues (in millions):			
Bundled gas sales:			
Residential	$ 2,759	$ 2,517	$ 2,325
Commercial	713	597	605
Other	140	61	123
Bundled gas revenues	3,612	3,175	3,053
Transportation service only revenue	1,346	1,211	1,249
Subtotal	4,958	4,386	4,302
Regulatory balancing accounts [(2)]	553	225	87
Total operating revenues	**$ 5,511**	**$ 4,611**	**$ 4,389**
Selected Statistics:			
Average annual residential usage (Mcf)	37	37	38
Average billed bundled gas sales revenues per Mcf:			
Residential	$ 16.54	$ 15.09	$ 13.88
Commercial	11.63	10.61	9.72
Net plant investment per customer	$ 4,130	$ 3,794	$ 3,522

(1) These amounts include natural gas provided by core transport agents and CCAs that procure their own supplies of natural gas for their respective customers.
(2) These amounts represent revenues authorized to be billed.

Competition

Trends in Market Demand and Competitive Conditions in the Electricity Industry

California law allows qualifying non-residential electric customers of IOUs to purchase electricity from energy service providers rather than from the utilities up to certain annual limits specified for each utility. This arrangement is known as DA. In 2018, the California legislature passed a bill to expand the annual statewide DA cap by 4,000 GWh and directed the CPUC to consider whether DA should be further expanded. In addition, California law permits cities, counties, and certain other public agencies that have qualified to become a CCA to generate or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses that do not affirmatively elect to continue to receive electricity generated or procured by a utility. In 2019, the CPUC issued an order implementing the 4,000 GWh increase for DA transactions, including an apportionment to the Utility's service area of approximately 1,873 GWh.

On June 24, 2021, the CPUC adopted a decision further implementing the 2018 legislation. In that decision, the CPUC recommended against further legislative expansion of DA at this time. Although a CPUC staff report issued in September 2020 had recommended expanding DA at a rate of ten percent each year, the CPUC ultimately found that recent reliability events and the current integrated resource planning forecasted needs for additional generation prevented a need for further DA reopening. The CPUC found that expanded DA would result in further fragmentation of the electric market in California and raise electric system reliability concerns. Additionally, the CPUC based its recommendation in part on DA providers' primary reliance on unspecified power sources, which it found may not support California's climate goals.

The Utility continues to provide transmission, distribution, metering, and billing services to DA customers at the election of their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Utility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of DA and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last resort for these customers. Section 387 of the Public Utilities Code allows for a request to transfer the responsibilities of the provider of last resort obligation from IOUs to other entities.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers employing qualifying renewable resources to receive bill credits at the full retail rate, are increasing, putting upward rate pressure on remaining customers. New NEM customers are required to pay an interconnection fee, utilize time of use rates, and are required to pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers or adopt self-generation technologies. See "Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE" in Item 1A. Risk Factors and "Regulatory Matters-OIR to Revisit Net Energy Metering Tariffs" in Item 7. MD&A.

Further, in some circumstances, governmental entities such as cities and irrigation districts may have authority under the state constitution or state statute to provide retail electric service directly to consumers. Those entities may rely upon FERC open access tariffs and Utility infrastructure to deliver energy to them at wholesale rates for resale at retail to existing or potential new Utility customers. These entities may also seek to acquire the Utility's transmission or distribution facilities through eminent domain for use in serving electricity at retail to existing or potential new Utility customers. During the Chapter 11 Cases, multiple entities communicated their interest in acquiring Utility assets through voluntary sales. It is also expected that some publicly-owned utilities will construct duplicate or new transmission or distribution facilities to serve existing or potential new Utility customers. In some instances, microgrid formation is a key factor in a community's choice to engage governmental entities.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO.

The effect of such types of retail competition generally is to reduce the number of utility customers, leading to a reduction in the Utility's rate base.

For risks in connection with increasing competition, see Item 1A. Risk Factors.

Competition in the Natural Gas Industry

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with other third-party storage providers, primarily in Northern California.

ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting estimates described in Item 7. MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with Item 7. MD&A and the Consolidated Financial Statements and related notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this 2021 Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risk Factors Summary

The following is a summary of the principal risks that could adversely affect our business, operations, and financial results. These risks are discussed more fully below.

Risks related to wildfires, including risks related to:

- The extent to which the Wildfire Fund and revised recoverability standard under AB 1054 effectively mitigates the risk of liability for damages arising from catastrophic wildfires;
- The 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or future wildfires;
- Recovery of excess costs in connection with wildfires; and
- Implementation of wildfire mitigation initiatives.

Risks related to operations and information technology, including risks related to:

- The hazardous nature of the Utility's electricity and natural gas operations;
- The Utility's insurance coverage;
- Changes in the electric power and gas industries;
- A cyber incident, cyber security breach, severe natural event or physical attack; and
- The operation and decommissioning of the Utility's nuclear generation facilities.

Risks related to environmental factors, including risks related to:

- Severe weather conditions, extended drought and climate change and events resulting from these conditions (including wildfires); and
- Extensive environmental laws.

Risks related to enforcement matters, investigations, and regulatory proceedings, including risks related to:

- The Enhanced Oversight and Enforcement Process;
- Legislative and regulatory developments;
- Outcomes of enforcement proceedings in connection with extensive regulations to which the Utility is subject; and
- Outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its costs.

Risks related to the environment and financial condition, including risks related to:

- PG&E Corporation's and the Utility's substantial indebtedness;
- Restrictions in indebtedness documents;
- Appeals of the Confirmation Order;
- Potential additional dilution to holders of PG&E Corporation common stock;
- Any substantial sale of stock by existing stockholders;
- Ownership and transfer restrictions associated with PG&E Corporation common stock;
- Tax-related risks and uncertainties, including the grantor trust election for the Fire Victim Trust;
- Restrictions on PG&E Corporation's and the Utility's ability to issue dividends;
- PG&E Corporation's reliance on dividends, distributions and other payments from the Utility;

- Restrictions on shareholders ability to change the direction or management of PG&E Corporation;
- The COVID-19 pandemic; and
- Increased customer rates.

General risks, including related to:

- Attracting and maintaining a qualified workforce or prolonged labor disruptions.

Risks Related to Wildfires

The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires.

If the Utility does not have an approved WMP, the Utility will not be issued a safety certification and will consequently not benefit from the presumption of prudency or the AB 1054 disallowance cap. Under AB 1054, the Utility is required to maintain a safety certification issued by the OEIS to be eligible for certain benefits, including a cap on Wildfire Fund reimbursement and a reformed prudent manager standard. The AB 1054 Wildfire Fund disallowance cap, which caps the amount of liability that the Utility could be required to bear for a catastrophic wildfire, is inapplicable 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 at the time the applicable wildfire ignited. In addition, if the Utility fails to maintain a valid safety certificate at the time a wildfire ignites, the initial burden of proof in a prudency proceeding shifts from intervenors to the Utility. The Utility will be required to reimburse amounts that are determined by the CPUC not to be just and reasonable. For more information on the disallowance cap, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Furthermore, 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. If the Utility is unable to maintain an AB 1054 safety certification or if the Wildfire Fund is exhausted, the ineffectiveness of the Wildfire Fund could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Also, 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.

The costs of participating in the Wildfire Fund are expected to exceed $6.7 billion over the anticipated ten-year contribution period for the fund. The timing and amount of any potential charges associated with the Utility's contributions would also depend on various factors. In addition, there could also be a significant delay between the occurrence of a wildfire and the timing on which the Utility recognizes impairment for the reduction in future coverage, due to the lack of data available to the Utility following a catastrophic event, especially if the wildfire occurs in the service territory of another participating electric utility. Participation in the Wildfire Fund is expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, and there can be no assurance that the benefits of participating in the Wildfire Fund ultimately outweigh these substantial costs.

PG&E Corporation and the Utility could be liable as a result of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, or future wildfires.

Based on the facts and circumstances available as of the date of this report, PG&E Corporation and the Utility have determined that it is probable they will incur losses in connection with the 2019 Kincade fire, the 2020 Zogg fire and the 2021 Dixie fire. Although PG&E Corporation and the Utility have recorded liabilities for probable losses in connection with these fires, these liability estimates correspond to the lower end of the range of reasonably estimable losses, do not include several categories of potential damages that are not reasonably estimable, and are subject to change based on new information.

Although there are a number of unknown facts surrounding Cal Fire's causation determinations of the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire, the Utility could be subject to significant liability in excess of recoveries that would be expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. PG&E Corporation and the Utility have also received and have responded or are responding to document, data, and other information requests from the CPUC's SED and law enforcement agencies that are investigating these wildfires. PG&E Corporation and the Utility could be the subject of additional investigations, lawsuits, or enforcement actions in connection with the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or other wildfires. For more information, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Under California law (including Penal Code section 1202.4), if the Utility were convicted of any of the charges in the Kincade Amended Complaint or the Zogg Complaint, the sentencing court must order the Utility to "make restitution to the victim or victims in an amount established by court order" that is "sufficient to fully reimburse the victim or victims for every determined economic loss incurred as the result of" the Utility's underlying conduct, in addition to interest and the victim's or victims' attorneys' fees. This requirement for full reimbursement of economic loss is not waivable by either the government or the victims and is not offset by any compensation that the victims have received or may receive from their insurance carriers. In the event that the Utility were convicted of certain charges in the Kincade Amended Complaint or the Zogg Complaint, the Utility currently believes that, depending on which charges it were to be convicted of, its total losses associated with each of the Kincade Amended Complaint and the Zogg Complaint would materially exceed the $800 million and the $375 million aggregate liability that PG&E Corporation and the Utility have recorded to reflect the lower end of the range of the reasonably estimable range of losses for the 2019 Kincade fire and 2020 Zogg fire civil claims, respectively. The Utility is currently unable to determine a reasonable estimate of the amount of such additional losses. The Utility does not expect that any of its liability insurance would be available to cover restitution payments ordered by the court presiding over the criminal proceeding.

There have also been numerous other wildfires in the Utility's service territory, of which the Utility has not been alleged or determined to be a cause. The Utility could be alleged or determined to be a cause of one or more of these wildfires.

Additionally, under the doctrine of inverse condemnation, courts have imposed liability 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, even if the utility is unable to recover these costs through rates. In fact, in December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it had incurred as a result of the doctrine of inverse condemnation. Legal challenges to that denial were unsuccessful. Plaintiffs have asserted and continue to assert the doctrine of inverse condemnation in lawsuits related to certain wildfires that occurred in the Utility's service territory. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities' electric transmission lines. While the Utility currently continues to dispute the applicability of inverse condemnation to the Utility, there can be no assurance that the Utility will be successful in challenging the applicability of inverse condemnation in the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire, or other litigation against PG&E Corporation or the Utility.

Although the Utility has taken extensive measures to reduce the threat of future wildfires, the potential that the Utility's equipment will be involved in the ignition of future wildfires, including catastrophic wildfires, is significant. This risk may be attributable to, and exacerbated by, a variety of factors, including climate (in particular extended periods of seasonal dryness coupled with periods of high wind velocities and other storms), infrastructure, and vegetation conditions. Despite significant investment in mitigation measures to improve infrastructure and manage vegetation, as well as implementation of de-energization strategies, the Utility may not be successful in mitigating the risk of future wildfires.

In addition, wildfires have had and, along with any future wildfires, could continue to have, adverse consequences on the Utility's proceedings with the CPUC (including the Safety Culture OII) and the FERC, and future regulatory proceedings, including future applications with the OEIS for the safety certification required by AB 1054. PG&E Corporation and the Utility may also suffer additional reputational harm and face an even more challenging operating, political, and regulatory environment as a result of the 2019 Kincade fire, the 2020 Zogg fire, the 2021 Dixie fire or any future wildfires. For more information about the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility may be unable to recover all or a significant portion of its excess costs in connection with wildfires from insurance, through rates, or from the Wildfire Fund in a timely manner.

The Utility could incur substantial costs in excess of insurance coverage or amounts potentially available under the Wildfire Fund under AB 1054 in the future in connection with the 2019 Kincade fire, the 2020 Zogg fire and the 2021 Dixie fire. There can be no assurance that the Utility will be allowed to recover costs in excess of insurance or amounts potentially available under the Wildfire Fund under AB 1054 in the future either through FERC TO rates or as costs recorded to the WEMA, 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. The inability to recover all or a significant portion of costs in excess of insurance through rates or by collecting such rates 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. For more information on wildfire recovery risk, see "The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires" above, "The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events and events resulting from these conditions (including wildfires), or may not be available at a reasonable cost, or available at all" below, and Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

The Utility may not effectively implement its wildfire mitigation initiatives.

The Utility's infrastructure is aging and poses risks to safety and system reliability. Although the Utility spends significant resources on initiatives designed to mitigate wildfire risks, there is no assurance that these initiatives will be successful or effective in reducing wildfire-related losses or that their costs will be fully recoverable through rates. The Utility will face a higher likelihood of catastrophic wildfires in its service territory if it cannot effectively implement these efforts and its WMPs. For example, the Utility may not be able to effectively implement its WMPs if it experiences unanticipated difficulties relative to sourcing, engaging, training, overseeing and retaining contract workers it needs to fulfill its mitigation obligations under the WMPs. The CPUC may assess penalties on the Utility if it finds that the Utility has failed to substantially comply with its WMPs.

There can be no assurance that the Utility's wildfire mitigation initiatives will be effective. For instance, a wildfire may be ignited and spread even in conditions that do not trigger proactive de-energization according to criteria for initiating a PSPS event. The Utility's inspections of vegetation near its assets may not detect structural weaknesses within a tree or other issues. If the Utility's wildfire mitigation initiatives are not effective, a wildfire could be ignited and spread.

The PSPS program has been subject to significant scrutiny and criticism by various stakeholders, including customers, regulators, and lawmakers. The Utility also is the subject of a class action litigation in connection with the 2019 PSPS events.

In addition, on a risk-informed basis, the Utility is making efforts to reduce the frequency and impacts of PSPS. The Utility may be subject to mandated changes to, or restrictions on, its operational practices, regulatory fines and penalties, claims for damages, and reputational harm if the Utility does not execute PSPS in compliance with applicable rules and regulations. The Utility establishes the criteria under which it implements PSPS in its territory. To the extent the Utility's criteria for implementing PSPS are not sufficient to mitigate the risk of wildfires, the Utility does not fully implement PSPS when criteria are met due to other overriding conditions or the Utility's regulators mandate changes to, or restrictions on, its criteria or other operational PSPS practices, the Utility will face a higher likelihood of catastrophic wildfires in its territory during high-risk weather conditions.

PG&E Corporation and the Utility cannot predict the timing and outcome of the various proceedings and litigation in connection with its wildfire mitigation initiatives. PG&E Corporation and the Utility could be subject to additional investigations, regulatory proceedings or other enforcement actions as well as to additional litigation and claims by customers as a result of the Utility's implementation of its wildfire mitigation initiatives, which could result in fines, penalties, customer rebates or other payments. The amount of any fines, penalties, customer rebates or other payments (if PG&E Corporation or the Utility were to issue any credits, rebates or other payments in connection with any other wildfire mitigation initiatives or liability for damages) 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 PSPS and EPSS programs have had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers and future PSPS and EPSS events may increase these negative perceptions. For more information, see "Regulatory Matters" in Item 7. MD&A.

Risks Related to Operations and Information Technology

The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks.

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system. See "Electric Utility Operations" and "Natural Gas Utility Operations" in Item 1. above. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives, and the CPUC approved retirement of Diablo Canyon by 2024 and 2025. For more information, see "The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements or operating conditions change or the facilities cease operations before the licenses expire" below.

The Utility's ability to efficiently construct, maintain, operate, protect, and decommission its facilities, and provide electricity and natural gas services safely and reliably is subject to numerous risks, many of which are beyond the Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines or other assets or group of assets, that can cause explosions, fires, public or workforce safety issues, large scale system disruption or other catastrophic events;
- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electrical black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for employees, contractors, or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, or the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wildfire or natural gas explosion);
- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;
- operator or other human error;
- a motor vehicle or aviation incident involving a Utility vehicle or aircraft, respectively (or one operated on behalf of the Utility) resulting in serious injuries to or fatalities of the workforce or the public, property damage, or other consequences;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;
- construction performed by third parties that damages the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines, the risk of which may be exacerbated if the Utility does not have an effective contract management system;

- the release of hazardous or toxic substances into the air, water, or soil, including, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and

- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war. For more information, see "The Utility's operational networks and information technology systems could be impacted by a cyber incident, cyber security breach, severe natural event or physical attack" below.

The occurrence of any of these events could interrupt fuel supplies, affect demand for electricity or natural gas, cause unplanned outages or reduce generating output, damage the Utility's assets or operations, damage the assets or operations of third parties on which the Utility relies, damage property owned by customers or others, and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore service, and to compensate third parties. Any of such incidents also could lead to significant claims against the Utility.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities, vegetation management, or the construction or demolition or facilities, the Utility may have less control over contractors than its employees and may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions.

Insurance, equipment warranties, or other contractual indemnification requirements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events and events resulting from these conditions (including wildfires), or may not be available at a reasonable cost, or available at all.

As a result of the potential application to IOUs of a strict liability standard under the doctrine of inverse condemnation, past losses recorded by insurance companies, past wildfires and the risk of increased wildfires including as a result of climate change, the Utility may not be able to obtain sufficient insurance coverage in the future at a reasonable cost, or at all.

The Utility has experienced increased costs and difficulties in obtaining insurance coverage for wildfires and other risks that could arise from the Utility's ordinary operations. PG&E Corporation, the Utility or its contractors and customers could continue to experience coverage reductions or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of the Utility's insurance coverage, including losses arising from litigation. Uninsured losses and increases in the cost of insurance may not be recoverable through rates. A loss that is not fully insured or cannot be recovered through rates, and increased insurance costs that are not recoverable, could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The electric power and gas industries are undergoing significant changes driven by technological advancements and a decarbonized economy.

The electric power industry is undergoing transformative change driven by technological advancements enabling customer choice and state climate policy supporting a decarbonized economy. California utilities also are experiencing increasing deployment by customers and third parties of distributed energy resources, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. These developments will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect distributed energy resources. In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g., rail and water projects). If the Utility is unable to effectively adapt to these changes, its business model and its ability to execute on its strategy could be materially impacted.

Various jurisdictions within California have enacted prohibitions or restrictions on use and consumption of natural gas, for example in buildings, that will reduce the use of natural gas. Reducing natural gas use could lead to a reduction in the gas customer base and a diminished need for gas infrastructure and, as a result, could lead to certain gas assets no longer being "used and useful," potentially causing substantial investment value of gas assets to be stranded (under CPUC precedent, when an asset no longer meets the standard of "used and useful," the asset is removed from rate base, which results in a reduction in associated rate recovery). However, while natural gas demand is projected to decline over time, the costs of operating a safe and reliable gas delivery system in California have been increasing, among other things, to cover the cost of long-term pipeline safety enhancements. Inability by the Utility to recover through rates its investments into the natural gas system while still ensuring gas system safety and reliability could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

These industry changes, costs associated with complying with new regulatory developments and initiatives and with technological advancements, or the Utility's inability to successfully adapt to changes in the electric and gas industry, could materially affect the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility's operational networks and information technology systems could be impacted by a cyber incident, cyber security breach, severe natural event, or physical attack.

The Utility's electricity and natural gas systems rely on a complex, interconnected network of generation, transmission, distribution, control, and communication technologies, which can be damaged by natural events-such as severe weather or seismic events-and by malicious events, such as cyber and physical attacks. Private and public entities, such as the North American Electric Reliability Corporation, and the U.S. federal government, including the Departments of Defense, Homeland Security and Energy, and the White House, have noted that cyber-attacks targeting utility systems are increasing in sophistication, magnitude, and frequency. The Utility's operational networks also may face new cyber security risks due to modernizing and interconnecting the existing infrastructure with new technologies and control systems. Any failure or decrease in the functionality of the Utility's operational networks could cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to safely generate, transport, deliver and store energy and gas or otherwise operate in the most safe and efficient manner or at all, and damage the Utility's assets or operations or those of third parties.

The Utility also relies on complex information technology systems that allow it to create, collect, use, disclose, store and otherwise process sensitive information, including the Utility's financial information, customer energy usage and billing information, and personal information regarding customers, employees and their dependents, contractors, and other individuals. In addition, the Utility often relies on third-party vendors to host, maintain, modify, and update its systems, and to provide other services to the Utility or the Utility's customers. In addition, the Utility is increasingly being required to disclose large amounts of data (including customer energy usage and personal information regarding customers) to support changes to California's electricity market related to grid modernization and customer choice. These third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience security incidents or inadequate security measures. Any incidents or disruptions in the Utility's information technology systems could impact the Utility's ability to track or collect revenues and to maintain effective internal controls over financial reporting.

The Utility and its third-party vendors have been subject to, and will likely continue to be subject to, breaches and attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these breaches or attempts has individually or in the aggregate resulted in a security incident with a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in material fines and penalties, loss of customers and harm to PG&E Corporation's and the Utility's reputation, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no assurance that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable through rates.

The operation and decommissioning of the Utility's nuclear generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements or operating conditions change or the facilities cease operations before the licenses expire.

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to operation of the Diablo Canyon nuclear generation units as well as the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses 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 Utility may be required under federal law to pay up to $275 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon units by 2024 and 2025. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before their respective licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge 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, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employee retention program to ensure adequate staffing levels at Diablo Canyon, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the Utility. There can be no assurance that the Utility will be successful in retaining highly skilled personnel under its employee programs.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. See "Regulatory Environment" in Item 1. Business above. If the Utility were unable to recover these costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon's two nuclear generation units before their respective licenses expire in 2024 and 2025. As of December 31, 2021, the Utility's unrecovered investment in Diablo Canyon was $1.16 billion.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. See "Asset Retirement Obligations" in Note 3 of the Notes to the Consolidated Financial Statement in Item 8. The Utility's costs to decommission its nuclear facilities through nuclear decommissioning are subject to reasonableness review by the CPUC. The Utility will be responsible for any costs that the CPUC determines were not reasonably incurred. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

Risks Related to Environmental Factors

Severe weather conditions, extended drought, and climate change could materially affect PG&E Corporation and the Utility.

Extreme weather, drought and shifting climate patterns have intensified the challenges associated with many of the other risks facing PG&E Corporation and the Utility, particularly wildfire management in California. The Utility's service territory encompasses some of the most densely forested areas in California and, as a consequence, is subject to higher risk from vegetation-related ignition events than other California IOUs. Further, environmental extremes, such as drought conditions and extreme heat followed by periods of wet weather, can drive additional vegetation growth (which can then fuel fires) and influence both the likelihood and severity of extraordinary wildfire events. In particular, the risk posed by wildfires, including during the 2021 wildfire season, has increased in the Utility's service area as a result of an ongoing extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases due to rising temperatures and record rainfall following the drought, and strong wind events, among other environmental factors. As of December 31, 2021, more than 86% of California is experiencing severe to extreme drought. Moderate or severe drought conditions occur and can persist in virtually all of the Utility's service territory. More than half of the Utility's service area is in an HFTD. Contributing factors other than environmental can include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk. In January 2018, the CPUC approved a statewide fire-threat map that shows that approximately half of the Utility's service territory is facing "elevated" or "extreme" fire danger. Approximately 25,000 circuit miles of the Utility's nearly 81,000 distribution overhead circuit miles and approximately 5,500 miles of the nearly 18,000 transmission overhead circuit miles are in such HFTDs, significantly more in total than other California IOUs.

Severe weather events and other natural disasters, including wildfires and other fires, storms, tornadoes, floods, extreme heat events (including recent extreme heat events during the 2021 wildfire season), drought, earthquakes, lightning, tsunamis, rising sea levels, pandemics, solar events, electromagnetic events, wind events or other weather-related conditions, climate change, or natural disasters, could result in severe business disruptions, prolonged power outages, property damage, injuries and loss of life, significant decreases in revenues and earnings, and significant additional costs to PG&E Corporation and the Utility. Any such event could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. Any of such events also could lead to significant claims against the Utility. Further, these events could result in regulatory penalties and disallowances, particularly if the Utility encounters difficulties in restoring power to its customers on a timely basis or if the related losses are found to be the result of the Utility's practices or the failure of electric and other equipment of the Utility.

Further, the Utility has been studying the potential effects of climate change (increased severity and frequency of storm events, sea level rise, land subsidence, change in temperature extremes, changes in precipitation patterns and drought, and wildfire) on its assets, operations, and services, and the Utility is developing adaptation plans to set forth a strategy for those events and conditions that the Utility believes are most significant. Consequences of these climate-driven events may vary widely and could include increased stress on the energy supply network due to new patterns of demand, reduced hydroelectric output, physical damage to the Utility's infrastructure, higher operational costs, and an increase in the number and duration of customer outages and safety consequences for both employees and customers. As a result, the Utility's hydroelectric generation could change, and the Utility would need to consider managing or acquiring additional generation. If the Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, climate hazards such as heatwaves, windstorms, and flooding caused by rising sea levels and extreme storms could damage the Utility's facilities, including gas, generation, and electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase. See "Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE" above.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

The Utility's operations are subject to extensive environmental laws, and such laws could change.

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, and orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. For more information, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future, or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover through rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. See "Environmental Regulation" in Item 1. and Note 15 of the Notes to the Consolidated Financial Statements in Item 8. The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination, changes in estimated costs, and the extent to which actual remediation costs differ from recorded liabilities have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Risks Related to Other Enforcement Matters, Investigations, and Regulatory Proceedings

PG&E Corporation and the Utility are subject to the Enhanced Oversight and Enforcement Process.

The EOEP is a six-step process with potentially escalating CPUC oversight and enforcement measures based on specific "triggering events" identified for each of the six steps. If the Utility is placed into the EOEP, it will be subject to additional reporting requirements and additional monitoring and oversight by the CPUC. Higher steps of the process (steps 3 through 6) also contemplate additional enforcement mechanisms, including appointment of an independent third-party monitor, appointment of a chief restructuring officer, pursuit of the receivership remedy, and review of the Utility's Certificate of Public Convenience and Necessity (i.e., its license to operate as a utility). The process contains provisions for the Utility to cure and exit the process if it can satisfy specific criteria. The EOEP states that the Utility should presumptively move through the steps of the process sequentially, but the CPUC may place the Utility into the appropriate step of the process upon occurrence of a specified triggering event.

On April 15, 2021, the CPUC placed the Utility into step 1 of the EOEP for failing to sufficiently prioritize clearing vegetation on its highest risk power lines as part of the 2020 WMP work. There can be no assurance regarding if or when the Utility will exit the EOEP, or whether the CPUC will initiate another step 1 proceeding or whether the CPUC will seek to move the Utility into a higher step of the process. See "Enforcement and Litigation Matters" in Item 7. MD&A.

PG&E Corporation and the Utility could be materially affected by legislative and regulatory developments.

The Utility is subject to extensive regulations. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Wildfire Fund does not effectively mitigate the financial risk of liability for damages arising from catastrophic wildfires where the Utility's facilities are a substantial cause. See "The Wildfire Fund and other provisions of AB 1054 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires." above.

In June 2018, the State of California enacted the CCPA, which went into effect on January 1, 2020, with a 12-month look-back period requiring compliance by January 1, 2019. The State of California announced enacted regulations in August 2020 and March 2021 which provide guidance on the requirements of the CCPA. The CCPA requires companies that process information on California residents to make new disclosures to consumers about their data collection, use and sharing practices, allows consumers to opt out of certain data sharing with third parties and provides a new cause of action for data breaches. The CCPA provides for financial penalties in the event of non-compliance and statutory damages in the event of a data security breach. On November 3, 2020, Californians voted to approve Proposition 24, a ballot measure that creates the California Privacy Rights Act (the "CPRA"), which amended and expanded the CCPA. The State of California enacted the CPRA in November 2020, with most provisions operative as of January 1, 2023 and applicable to personal information collected beginning January 1, 2022. Failure to comply with the CCPA and the CPRA could result in the imposition of material fines imposed on PG&E Corporation and the Utility.

Also, SB 100 (the 100 Percent Clean Energy Act of 2018) increased the percentage from 50% to 60% of California's electricity portfolio that must come from renewables by 2030; and established state policy that 100% of all retail electricity sales must come from renewable portfolio standard-eligible or carbon-free resources by 2045. Failure to comply with SB 100 could result in fines imposed on PG&E Corporation and the Utility that could be material.

The Utility is subject to extensive regulations and the risk of enforcement proceedings in connection with compliance with such regulations.

The Utility is subject to extensive regulations, including federal, state, and local energy, environmental and other laws and regulations, and the risk of enforcement proceedings in connection with compliance with such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the Safety Culture OII (as defined in "Order Instituting an Investigation into PG&E Corporation's and the Utility's Safety Culture" under "Enforcement and Litigation Matters" in Item 7. MD&A) and other matters that the CPUC's SED may be investigating. The SED could launch investigations at any time on any issue it deems appropriate. In addition, OEIS has authority to approve and oversee compliance with the WMP.

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state, or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and RA requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC GOs or other applicable CPUC decisions or regulations; whether the Utility is able to achieve the targets in its WMPs; federal electric reliability standards; and environmental compliance. CPUC staff could also impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The Utility also is a target of a number of investigations, in addition to certain investigations in connection with the wildfires. See "Risks Related to Wildfires," above. The Utility is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility, or the amount of any costs and expenses associated with such investigations.

If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties the amount of which could be substantial and, in the event of a judgment against the Utility, suffer further ongoing negative consequences. Furthermore, a negative outcome in any of these investigations, or future enforcement actions, could negatively affect the outcome of future ratemaking and regulatory proceedings to which the Utility may be subject; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations.

The Utility's ratemaking and cost recovery proceedings may not authorize sufficient revenues, or the Utility's actual costs could exceed its authorized or forecasted costs due to various factors, including if the Utility is not able to manage its costs effectively.

The Utility's financial results depend on its ability to earn a reasonable return on capital, including long-term debt and equity, and to recover costs from its customers, through the rates it charges its customers as approved by the CPUC and the FERC. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility or if the amount of actual costs incurred differs from the forecast or authorized costs embedded in rates. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services. If the CPUC does not authorize sufficient funding for investments in the Utility's infrastructure, it may negatively impact the Utility's ability to modernize the grid and make it resilient to risks related to climate change, including wildfires.

In addition to the amount of authorized revenues, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility's actual costs differ from authorized or forecast costs. The Utility's ability to recover its costs and earn a reasonable rate of return can be affected by many factors, including the time delay between when costs are incurred and when those costs are recovered through rates. The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. Further, the Utility may be required to incur expenses before the relevant regulatory agency approves the recovery of such costs. For example, the Utility has incurred, and continues to incur, costs to strengthen its wildfire mitigation and prevention efforts before it is clear whether such costs will be recoverable through rates. Also, the CPUC may deny recovery of uninsured wildfire- related costs incurred by the Utility if the CPUC determines that the Utility was not prudent.

The Utility may incur additional costs or reduced revenue for many reasons including changing market circumstances, unanticipated events (such as wildfires, storms, earthquakes, accidents, or catastrophic or other events affecting the Utility's operations), increased self-generation by customers, an increase in distributed generation, lower customer demand due to adverse economic conditions, the loss of the Utility's customers to other retail providers like CCAs or DA providers, whether the CAISO wholesale electricity market continues to function effectively, returning customers, or compliance with new state laws or policies. See "Competition in the Electricity Industry" in Item 1.

Risks Related to PG&E Corporation's and the Utility's Environment and Financial Condition

PG&E Corporation's and the Utility's substantial indebtedness may adversely affect their financial health and operating flexibility.

PG&E Corporation and the Utility have a substantial amount of indebtedness, most of which is secured by liens on certain assets of PG&E Corporation and the Utility. As of December 31, 2021, PG&E Corporation had approximately $4.71 billion of outstanding indebtedness (such indebtedness consisting of PG&E Corporation's $1.0 billion aggregate principal amount of senior secured notes due 2028, $1.0 billion aggregate principal amount of senior secured notes due 2030, and borrowings under the $2.75 billion secured term loan agreement entered into in June 2020), and the Utility had approximately $38.3 billion of outstanding indebtedness (such indebtedness including outstanding First Mortgage Bonds, borrowings under the Utility Revolving Credit Agreement and borrowings under the Utility Term Loan Credit Agreement). In addition, PG&E Corporation had $500 million of additional borrowing capacity under the Corporation Revolving Credit Agreement, and the Utility had $1.4 billion of additional borrowing capacity under the Utility Revolving Credit Agreement. In addition, the Utility had outstanding preferred stock with an aggregate liquidation preference of $252 million.

Since PG&E Corporation and the Utility have a high level of debt, a substantial portion of cash flow from operations will be used to make payments on this debt. Furthermore, since a significant percentage of the Utility's assets are used to secure its debt, this reduces the amount of collateral available for future secured debt or credit support and reduces its flexibility in operating these secured assets. This relatively high level of debt and related security could have other important consequences for PG&E Corporation and the Utility, including:

- limiting their ability or increasing the costs to refinance their indebtedness;
- limiting their ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of their business strategy or other purposes;

- limiting their ability to use operating cash flow in other areas of their business;
- increasing their vulnerability to general adverse economic and industry conditions, including increases in interest rates, particularly given their substantial indebtedness that bears interest at variable rates, as well as to catastrophic events; and
- limiting their ability to capitalize on business opportunities.

Under the terms of the agreements and indentures governing their respective indebtedness, PG&E Corporation and the Utility are permitted to incur additional indebtedness, some of which could be secured (subject to compliance with certain tests) and which could further accentuate these risks. As a result of the high level of indebtedness, PG&E Corporation and the Utility may be unable to generate sufficient cash through operations to service such debt, and may need to refinance such indebtedness at or prior to maturity and be unable to obtain financing on suitable terms or at all. As a capital-intensive company, the Utility relies on access to the capital markets. If the Utility were unable to access the capital markets or the cost of financing were to substantially increase, its financial condition, results of operations, liquidity, and cash flows could be materially affected. The Utility's ability to obtain financing, as well as its ability to refinance debt and make scheduled payments of principal and interest, are dependent on numerous factors, including the Utility's levels of indebtedness, maintenance of acceptable credit ratings, financial performance, liquidity and cash flow, and other market conditions. The Utility's inability to service its substantial debt or access the financial markets on reasonable terms could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The documents that govern PG&E Corporation's and the Utility's indebtedness limit their flexibility in operating their business.

PG&E Corporation's and the Utility's material financing agreements, including certain of their respective credit agreements and indentures, contain various covenants restricting, among other things, their ability to:

- incur or assume indebtedness or guarantees of indebtedness;
- incur or assume liens;
- sell or dispose of all or substantially all of its property or business;
- merge or consolidate with other companies;
- enter into any sale leaseback transactions; and
- enter into swap agreements.

The restrictions contained in these material financing agreements could affect PG&E Corporation's and the Utility's ability to operate their business and may limit their ability to react to market conditions or take advantage of potential business opportunities as they arise. For example, such restrictions could adversely affect PG&E Corporation's and the Utility's ability to finance their operations and expenditures, make strategic acquisitions, investments or alliances, sell assets, restructure their organization or finance their capital needs. Additionally, PG&E Corporation's and the Utility's ability to comply with these covenants and restrictions may be affected by events beyond their control, including prevailing regulatory, economic, financial and industry conditions.

Parties have appealed the Confirmation Order.

Following entry of the Confirmation Order confirming the Plan, certain parties filed notices of appeal with respect to the Confirmation Order. While a number of such appeals have been dismissed, there can be no assurance that any of the remaining appeals will not be successful and, if successful, that any such appeal would not have a material adverse effect on PG&E Corporation and the Utility.

PG&E Corporation may be required to issue shares with respect to HoldCo Rescission or Damage Claims, which would result in dilution to holders of PG&E Corporation common stock, or pay a material amount of cash with respect to allowed Subordinated Debt Claims.

On the Emergence Date, PG&E Corporation issued to the Fire Victim Trust a number of shares of common stock equal to 22.19% of the outstanding common stock on such date. As further described in "Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8, PG&E Corporation may be required to issue shares of its common stock in satisfaction of allowed HoldCo Rescission or Damage Claims. If such issuance is required, it may be determined that, under the Plan, the Fire Victim Trust should receive additional shares of PG&E Corporation common stock such that it would have owned 22.19% of the outstanding common stock of reorganized PG&E Corporation on the Emergence Date, assuming that such issuance of shares in satisfaction of the HoldCo Rescission or Damage Claims had occurred on the Emergence Date. Any such issuances will result in dilution to anyone who holds shares of PG&E Corporation common stock prior to such issuance and may cause the trading price of PG&E Corporation shares to decline.

Additionally, PG&E Corporation may be required to pay a material amount of cash with respect to allowed Subordinated Debt Claims (as defined in "Satisfaction of HoldCo Rescission or Damage Claims and Subordinated Debt Claims" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8). Such payment may have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Any substantial sale of stock by existing stockholders could depress the market value of PG&E Corporation's common stock, thereby devaluing the market price.

Certain stockholders, including the Fire Victim Trust, received a large number of shares in the Chapter 11 Cases and may continue to hold shares of PG&E Corporation. PG&E Corporation can make no prediction as to the effect, if any, that sales of shares, or the availability of shares for future sale, will have on the prevailing market price of shares of PG&E Corporation common stock. Sales of substantial amounts of shares of common stock in the public market, or the perception that such sales could occur, could depress prevailing market prices for such shares. Such sales may also make it more difficult for PG&E Corporation to sell equity securities or equity-linked securities in the future at a time and price which it deems appropriate.

PG&E Corporation may also sell additional shares of common stock in subsequent offerings or issue additional shares of common stock or securities convertible into shares of PG&E Corporation common stock. The issuance of any shares of PG&E Corporation common stock in future financings, acquisitions upon conversion or exercise of convertible securities, or otherwise may result in a reduction of the book value and market price of PG&E Corporation's outstanding common stock. If PG&E Corporation issues any such additional shares, the issuance will cause a reduction in the proportionate ownership and voting power of all current shareholders. PG&E Corporation cannot predict the size of future issuances of shares of PG&E Corporation common stock or securities convertible into shares of PG&E Corporation common stock or, for any issuance, the effect, if any, that such future issuances will have on the market price of PG&E Corporation's common stock.

PG&E Corporation common stock is subject to ownership and transfer restrictions intended to preserve PG&E Corporation's ability to use its net operating loss carryforwards and other tax attributes.

PG&E Corporation has incurred and may also continue to incur in connection with the Plan significant net operating loss carryforwards and other tax attributes, the amount and availability of which are subject to certain qualifications, limitations and uncertainties. The Amended Articles (as defined below) impose certain restrictions on the transferability and ownership of PG&E Corporation common stock and preferred stock (together, the "capital stock") and other interests designated as "stock" of PG&E Corporation by the Board of Directors as disclosed in an SEC filing (such stock and other interests, the "Equity Securities," and such restrictions on transferability and ownership, the "Ownership Restrictions") in order to reduce the possibility of an equity ownership shift that could result in limitations on PG&E Corporation's ability to utilize net operating loss carryforwards and other tax attributes from prior taxable years or periods for federal income tax purposes. Any acquisition of PG&E Corporation capital stock that results in a shareholder being in violation of these restrictions may not be valid.

Subject to certain exceptions, the Ownership Restrictions restrict (i) any person or entity (including certain groups of persons) from directly or indirectly acquiring or accumulating 4.75% or more of the outstanding Equity Securities and (ii) the ability of any person or entity (including certain groups of persons) already owning, directly or indirectly, 4.75% or more of the Equity Securities to increase their proportionate interest in the Equity Securities. For more information, see "Because PG&E Corporation and the Utility have elected to treat the Fire Victim Trust as a grantor trust, the application of the Ownership Restrictions, as defined in PG&E Corporation's Amended Articles of Incorporation, will be determined on the basis of a number of shares outstanding that could differ materially from the number of shares reported as outstanding on the cover page of its periodic reports under the Exchange Act" below. Any transferee receiving Equity Securities that would result in a violation of the Ownership Restrictions will not be recognized as a shareholder of PG&E Corporation or entitled to any rights of shareholders, including, without limitation, the right to vote and to receive dividends or distributions, whether liquidating or otherwise, in each case, with respect to the Equity Securities causing the violation.

The Ownership Restrictions remain in effect until the earliest of (i) the repeal, amendment, or modification of Section 382 (and any comparable successor provision) of the Internal Revenue Code, in a manner that renders the restrictions imposed by Section 382 of the Internal Revenue Code no longer applicable to PG&E Corporation, (ii) the beginning of a taxable year in which the Board of Directors of PG&E Corporation determines that no tax benefits attributable to net operating losses or other tax attributes are available, (iii) the date selected by the Board of Directors if it determines that the limitation amount imposed by Section 382 of the Internal Revenue Code as of such date in the event of an "ownership change" of PG&E Corporation (as defined in Section 382 of the Internal Revenue Code and Treasury Regulation Sections 1.1502-91 et seq.) would not be materially less than the net operating loss carryforwards or "net unrealized built-in loss" (within the meaning of Section 382 of the Internal Revenue Code and Treasury Regulation Sections 1.1502-91 et seq.) of PG&E Corporation, and (iv) the date selected by the Board of Directors if it determines that it is in the best interests of PG&E Corporation's shareholders for the Ownership Restrictions to be removed or released. The Ownership Restrictions may also be waived by the Board of Directors on a case by case basis.

Because PG&E Corporation and the Utility have elected to treat the Fire Victim Trust as a grantor trust, the application of the Ownership Restrictions, as defined in PG&E Corporation's Amended Articles of Incorporation, will be determined on the basis of a number of shares outstanding that could differ materially from the number of shares reported as outstanding on the cover page of its periodic reports under the Exchange Act.

The Plan contemplated that the Fire Victim Trust would be treated as a "qualified settlement fund" for U.S. federal and state income tax purposes, subject to PG&E Corporation's ability to elect to treat the Fire Victim Trust as a grantor trust for U.S. federal and state income tax purposes instead. On July 8, 2021, PG&E Corporation, the Utility, ShareCo, and the Fire Victim Trust entered into the Share Exchange and Tax Matters Agreement, pursuant to which PG&E Corporation and the Utility made a grantor trust election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

As a result of the grantor trust election, shares of PG&E Corporation common stock owned by the Fire Victim Trust are treated as held by the Utility and, in turn attributed to PG&E Corporation for income tax purposes. Consequently, any shares owned by the Fire Victim Trust are effectively excluded from the total number of outstanding equity securities when calculating a person's Percentage Stock Ownership (as defined in the Amended Articles) for purposes of the Ownership Restrictions. See "Tax Matters" in Item 7. MD&A for an example of these calculations. PG&E Corporation does not control the number of shares held by the Fire Victim Trust and is not able to determine in advance the number of shares the Fire Victim Trust will hold. PG&E Corporation intends to periodically make available to investors information about the number of shares of common stock held by the Fire Victim Trust, the Utility, and ShareCo as of a specified date for purposes of the Ownership Restrictions, including in its Quarterly Reports and Annual Reports filed with the SEC.

PG&E Corporation intends to enforce the Ownership Restrictions as described in the foregoing paragraph (calculated as excluding any shares owned by the Fire Victim Trust, the Utility, and ShareCo from the number of outstanding equity securities). All current and prospective shareholders are advised to consider the foregoing in determining their ownership and acquisition of PG&E Corporation common stock.

PG&E Corporation may not be able to use some or all of its net operating loss carryforwards and other tax attributes to offset future income.

As of December 31, 2021, PG&E Corporation had net operating loss carryforwards for PG&E Corporation's consolidated group for U.S. federal and California income tax purposes of approximately $21.1 billion and $18.9 billion, respectively, and PG&E Corporation incurred and may also continue to incur in connection with the Plan significant net operating loss carryforwards and other tax attributes. The ability of PG&E Corporation to use some or all of these net operating loss carryforwards and certain other tax attributes may be subject to certain limitations. Under Section 382 of the Internal Revenue Code (which also applies for California state income tax purposes), if a corporation (or a consolidated group) undergoes an "ownership change," such net operating loss carryforwards and other tax attributes may be subject to certain limitations. 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).

As of the date of this report, it is more likely than not that PG&E Corporation has not undergone an ownership change and its net operating loss carryforwards and other tax attributes are not limited by Section 382 of the Internal Revenue Code. However, whether PG&E Corporation underwent or will undergo an ownership change as a result of the transactions in PG&E Corporation's equity that occurred pursuant to the Plan depends on several factors outside PG&E Corporation's control and the application of certain laws that are uncertain in several respects. Accordingly, there can be no assurance that the IRS would not successfully assert that PG&E Corporation has undergone or will undergo an ownership change pursuant to the Plan. In addition, even if these transactions did not cause an ownership change, they may increase the likelihood that PG&E Corporation may undergo an ownership change in the future. If the IRS successfully asserts that PG&E Corporation did undergo, or PG&E Corporation otherwise does undergo, an ownership change, the limitation on its net operating loss carryforwards and other tax attributes under Section 382 of the Internal Revenue Code could be material to PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

In particular, limitations imposed on PG&E Corporation's ability to utilize net operating loss carryforwards or other tax attributes could cause U.S. federal and California income taxes to be paid earlier than would be paid if such limitations were not in effect and could cause such net operating loss carryforwards or other tax attributes to expire unused, in each case reducing or eliminating the benefit of such net operating loss carryforwards and other tax attributes. In addition, PG&E Corporation's ability to utilize its net operating loss carryforwards is critical to a successful rate-neutral securitization transaction and to PG&E Corporation's and the Utility's commitment to make certain operating and capital expenditures. Failure to consummate a securitization transaction or obtain alternative sources of capital could have a material adverse effect on PG&E Corporation and the Utility and the value of PG&E Corporation common stock.

PG&E Corporation's ability to pay dividends on shares of its common stock is subject to restrictions.

Pursuant to the Confirmation Order, PG&E Corporation may not pay dividends on shares of its common stock until it recognizes $6.2 billion in Non-GAAP Core Earnings following the Emergence Date. "Non-GAAP Core Earnings" means GAAP earnings adjusted for certain non-core items.

Subject to the foregoing restrictions, any decision to declare and pay dividends in the future will be made at the discretion of the Board of Directors and will depend on, among other things, PG&E Corporation's results of operations, financial condition, cash requirements, contractual restrictions, and other factors that the Board of Directors may deem relevant.

PG&E Corporation is a holding company and relies on dividends, distributions and other payments, advances, and transfers of funds from the Utility to meet its obligations.

PG&E Corporation conducts its operations primarily through its subsidiary, the Utility, and substantially all of PG&E Corporation's consolidated assets are held by the Utility. Accordingly, PG&E Corporation's cash flow and its ability to meet its debt service obligations under its existing and future indebtedness are largely dependent upon the earnings and cash flows of the Utility and the distribution or other payment of these earnings and cash flows to PG&E Corporation in the form of dividends or loans or advances and repayment of loans and advances from the Utility. The ability of the Utility to pay dividends or make other advances, distributions, and transfers of funds will depend on its results of operations and may be restricted by, among other things, applicable laws limiting the amount of funds available for payment of dividends and certain restrictive covenants contained in the agreements of those subsidiaries. Additionally, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and to meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation. 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. As of January 31, 2022, there were $59.1 million of such cumulative and unpaid dividends on the Utility's preferred stock. In addition, the CPUC has imposed various conditions that govern the relationship between PG&E Corporation and the Utility, including financial conditions that require the Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, payable on May 13, 2022, to holders of record on April 29, 2022 and declared a dividend on the Utility's preferred stock totaling $3.5 million that will be accrued during the three-month period ending April 30, 2022, payable on May 15, 2022, to holders of record on April 29, 2022. It is uncertain when PG&E Corporation and the Utility will commence the payment of dividends on their common stock. The deterioration of income from, or other available assets of, the Utility for any reason could limit or impair the Utility's ability to pay dividends or other distributions to PG&E Corporation, which could, in turn, materially and adversely affect PG&E Corporation's ability to meet its obligations.

California law and certain provisions in the Amended Articles and the amended and restated bylaws of PG&E Corporation (the "Amended Bylaws") may prevent efforts by shareholders to change the direction or management of PG&E Corporation.

The Amended Articles and the Amended Bylaws contain provisions that may make the acquisition of PG&E Corporation more difficult without the approval of the Board of Directors, including the following:

- until 2024, the Board of Directors will be divided into two equal classes, with members of each class elected in different years for different terms;
- only holders of shares who are entitled to cast ten percent or more of the votes can request a special meeting of the shareholders, and any such request must satisfy the requirements specified in the Amended Bylaws; action by shareholders may otherwise only be taken at an annual or special meeting duly called by or at the direction of a majority of the Board of Directors, or action by written consent signed by shareholders owning at least the number of votes necessary to authorize the action at a meeting where all shares entitled to vote were present;
- advance notice for all shareholder proposals is required; and
- any person acquiring PG&E Corporation Equity Securities will be restricted from owning 4.75% or more of such Equity Securities (as determined for federal income tax purposes (see "Tax Matters" in Item 7. MD&A)), subject to certain exceptions as may be determined by the Board of Directors of PG&E Corporation.

These and other provisions in the Amended Articles, the Amended Bylaws, and California law could make it more difficult for shareholders or potential acquirers to obtain control of the Board of Directors or initiate actions that are opposed by the then-current Board of Directors, including delaying or impeding merger, tender offer, or proxy contest involving PG&E Corporation. The existence of these provisions could negatively affect the price of PG&E Corporation common stock and limit opportunities for shareholders to realize value in a corporate transaction.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been (beginning in March 2020) and could continue to be significantly affected by the outbreak of the COVID-19 pandemic (and its variants), but the extent of such impact is uncertain.

PG&E Corporation and the Utility continue to evaluate the impact of the current COVID-19 outbreak on their business and financial results. The consequences of a continued and prolonged outbreak and resulting governmental and regulatory orders have had and could continue to have a negative impact on the Utility's financial condition, results of operations, liquidity, and cash flows.

The outbreak of the COVID-19 pandemic and the resulting economic conditions, and resulting decrease in economic and industrial activity in the Utility's service territory, have and will continue to have a significant adverse impact on the Utility's customers. These circumstances have impacted and will continue to impact the Utility for a period of time that PG&E Corporation and the Utility are unable to predict. For example, the economic downturn has resulted in a reduction in customer receipts and collection delays throughout the COVID-19 pandemic.

The Utility's accounts receivable balances over 30 days outstanding as of December 31, 2021 were approximately $1.1 billion, or $832 million higher as compared to the balances as of December 31, 2019. The Utility is unable to estimate the portion of the increase directly attributable to the COVID-19 pandemic. The Utility expects to continue experiencing an impact on monthly cash collections for as long as current COVID-19 circumstances persist.

On January 1, 2021, electric rates were reset using sales that were adjusted for the COVID-19 pandemic impacts and significant ongoing shortfalls are not currently expected in 2021. PG&E Corporation and the Utility are currently unable to quantify the long-term potential impact of the changes in customer collections or changes in energy demand on earnings and cash flows due, in part, to uncertainties regarding the timing, duration and intensity of the COVID-19 outbreak and the resulting economic downturn. Although the CPUC authorized the establishment of memorandum and balancing accounts to track costs associated with customer protection measures, the timing of regulatory relief, if any, and ultimate cost recovery from such accounts or otherwise, are uncertain.

The COVID-19 pandemic and resulting economic downturn have resulted and will continue to result in workforce disruptions, both in personnel availability (including a reduction in contract labor resources) and deployment. Increased governmental regulation of the COVID-19 pandemic protections, including vaccination mandates or testing requirement for workers, could result in employee attrition, workforce disruptions and increased supplier and contractor costs.

Although the Utility continues to prioritize customer and community safety, these disruptions necessitate changes to the Utility's operating and capital expenditure plans, which could lead to project delays or service disruptions in certain programs. Delays in production and shipping of materials used in the Utility's operations may also impact operations.

The Utility has experienced shortages in certain materials, longer lead times and delivery delays as a result of domestic and international raw material and labor shortages. If these disruptions to the supply chain persist or worsen, the Utility may be delayed or prevented from completing planned maintenance and capital projects work.

PG&E Corporation and the Utility expect additional financial impacts in the future as a result of the COVID-19 pandemic. Potential longer-term impacts of the COVID-19 pandemic on PG&E Corporation or the Utility include the potential for higher credit spreads, borrowing costs and incremental financing needs. PG&E Corporation's and the Utility's analysis of the potential impact of the COVID-19 pandemic is ongoing and subject to change. PG&E Corporation and the Utility are unable to predict the timing, duration or intensity of the COVID-19 pandemic situation and any resurgence of the COVID-19 pandemic and any variant strains of the COVID-19 virus, the effectiveness and intensity of measures to contain the COVID-19 pandemic (including availability and effectiveness of vaccines), and the effects of the COVID-19 situation on the business, financial condition and results of operations of PG&E Corporation and the Utility and on the business and general economic conditions in the State of California and the United States of America.

Rising rates for the Utility's customers could result in circumstances in which the Utility is unable to fully recover costs or earn its authorized ROE.

The rates paid by the Utility's customers are impacted by the Utility's costs, commodity prices, and broader energy trends. The Utility's capital investment plan, increasing procurement of renewable power and energy storage, increasing environmental regulations, leveling demand, and the cumulative impact of other public policy requirements, collectively place continuing upward pressure on customer rates. In particular, the Utility will need to make substantial, sustained investments to its infrastructure to adapt to climate change. For more information on factors that could cause the Utility's costs to increase, see "The Utility's ratemaking and cost recovery proceedings may not authorize sufficient revenues, or the Utility's actual costs could exceed its authorized or forecasted costs due to various factors, including if the Utility is not able to manage its costs effectively" above. If customer rates increase, the CPUC may face greater pressure to approve lesser amounts in the Utility's ratemaking or cost recovery proceedings.

The Utility generally recovers its electricity and natural gas procurement costs through rates as "pass-through" costs. Increases in the Utility's commodity costs directly impact customer bills.

Increasing levels of self-generation of electricity by customers (primarily solar installations) and customer enrollment in NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, shifts costs to other customers. Under this structure, NEM customers do not pay their proportionate share of the cost of maintaining and operating the electric transmission and distribution system, subject to certain exceptions, while still receiving electricity from the system when their self-generation is inadequate to meet their electricity needs. These unpaid costs are subsidized by customers not participating in NEM. Accordingly, as more electric customers switch to NEM and self-generate energy, the burden on the remaining customers increases, which in turn encourages more self-generation, further increasing rate pressure on existing non-NEM customers.

Other long-term trends could also increase costs for gas customers. Natural gas providers are subject to compliance with CARB's cap-and-trade program, and natural gas end-use customers have an increasing exposure to carbon costs under the program through 2030 (when the full cost will be reflected in customer bills). CARB may also require aggressive energy efficiency programs to reduce natural gas end use. Increased renewable portfolio standards generation in the electric sector could reduce electric generation gas load. Additionally, customers replacing natural gas appliances with electric appliances will lead to further reduced gas demand. The combination of reduced load and increased costs to maintain the gas system could result in higher natural gas customer bills. In addition, some local city governments have passed ordinances restricting use of natural gas in new construction and, if other jurisdictions follow suit, this could affect future demand for the provision of natural gas. If fewer customers receive gas from the Utility, the Utility's gas system maintenance costs, many of which cannot be reduced in the short term even if gas quantities decrease, would be borne by fewer customers. Finally, a potential mandate to purchase renewable natural gas for core customers could lead to cost recovery risk if utilities are competing with the transportation sector without receiving the same incentives.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further reduce energy demand. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technology, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could increase the energy rates for other customers.

If rates were to rise too rapidly, customer usage could decline. This decline would decrease the volume of sales, among which the Utility's fixed costs are allocated, and increase rates.

To relieve some of this upward rate pressure, the CPUC may authorize lower revenues than the Utility requested or increase the period over which the Utility is allowed to recover amounts, which could impact the Utility's ability to timely recover its operating costs. The Utility's level of authorized capital investment could decline as well, leading to a slower growth in rate base and earnings. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

General Risk Factors

The Utility may be unable to attract and retain qualified personnel and senior management talent, or prolonged labor disruptions may occur.

The Utility's workforce is aging, and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility's employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceedings and the Chapter 11 Cases. Any such occurrences could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. For more information about labor disruptions related to the COVID-19 pandemic, see "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic" above.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utility owns or has obtained the right to occupy or use real property comprising the Utility's electricity and natural gas distribution facilities, electric generation facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under "Electric Utility Operations" and "Natural Gas Utility Operations." The Utility occupies or uses real property primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 9 million square feet of real property, including 7 million square feet owned by the Utility. On September 17, 2021, the sale of the SFGO closed and the Utility entered into a leaseback agreement with the new SFGO owner (the "Leaseback Agreement") to lease back certain space within the SFGO to allow for additional time to relocate critical facilities to other Utility sites. The Leaseback Agreement commenced on September 17, 2021 and continues through various dates for the various leased spaces, with December 31, 2023 being the latest lease expiration date. On October 23, 2020, the Utility entered into an office lease agreement with BA2 300 Lakeside LLC for approximately 910,000 rentable square feet of space within the Lakeside Building to serve as the Utility's principal administrative headquarters. The term of the lease will begin on or about April 8, 2022 and the lease grants the Utility an option to purchase the legal parcel that contains the Lakeside Building. For more information, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire and be surrendered at the end of February 2022.

The Utility currently owns approximately 148,000 acres of land, including approximately 121,000 acres of watershed lands. In 2002, the Utility agreed to implement its Land Conservation Commitment ("LCC") to permanently preserve the six "beneficial public values" on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 40,000 acres of the watershed lands available for donation to qualified organizations. The six "beneficial public values" being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility's goal is to implement all the LCC transactions by the end of 2023, subject to securing all required regulatory approvals.

ITEM 3. LEGAL PROCEEDINGS

PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding material lawsuits and proceedings, see "Enforcement and Litigation Matters" in Item 7. MD&A, Item 1A. Risk Factors and Notes 2, 14, and 15 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following individuals serve as executive officers of PG&E Corporation, as of February 10, 2022. Except as otherwise noted, all positions have been held at PG&E Corporation.

Name	Age	Positions Held Over Last Five Years	Time in Position
Patricia K. Poppe	53	Chief Executive Officer	January 4, 2021 to present
		President and Chief Executive Officer, CMS Energy Corporation	July 2016 to December 2020
		Vice President, Customer Experience, Rates and Regulations, Consumers Energy Company	January 2011 to July 2016
Christopher A. Foster	43	Executive Vice President and Chief Financial Officer	March 24, 2021 to present
		Vice President and Interim Chief Financial Officer	September 26, 2020 to March 23, 2021
		Vice President, Treasury and Investor Relations	March 9, 2020 to September 25, 2020
		Senior positions within PG&E Corporation's Investor Relations department, including as its Vice President starting in December 2018	November 2017 to March 8, 2020
		Senior positions within PG&E Corporation and the Utility, including Director, Integrated Grid Planning and Innovation from June 2016 to October 2017	September 2011 to October 2017
Carla J. Peterman	43	Executive Vice President, Corporate Affairs and Chief Sustainability Officer	June 1, 2021 to present
		Senior Vice President, Strategy and Regulatory Affairs, Southern California Edison	September 2019 to May 2021
		Commissioner, California Public Utilities Commission	December 2012 to December 2018
Julius Cox	50	Executive Vice President, People, Shared Services and Supply Chain, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2021 to present
		Senior Vice President & Chief Human Resources Officer, American Electric Power	October 2019 to January 2021
		Executive Vice President & Chief Transformation Officer, Dynegy Inc.	September 2017 to April 2018
		Executive Vice President & Chief Administrative Officer, Dynegy Inc.	October 2014 to September 2017
Ajay Waghray	60	Senior Vice President and Chief Information Officer	September 21, 2020 to present
		Founder, Agni Growth Ventures, LLC	January 2019 to September 2021
		Executive Vice President and Chief Technology Officer, Assurant Inc.	May 2016 to December 2018
Sumeet Singh	43	Executive Vice President, Chief Risk Officer and Chief Safety Officer, PG&E Corporation and Pacific Gas and Electric Company	January 1, 2022 to present

		Senior Vice President and Chief Risk Officer, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2021 to December 31, 2021
		Interim President and Chief Risk Officer, Pacific Gas and Electric Company; Senior Vice President and Chief Risk Officer, PG&E Corporation	January 1, 2021 to January 31, 2021
		Senior Vice President and Chief Risk Officer, PG&E Corporation and Pacific Gas and Electric Company	August 2020 to December 31, 2021
		Gas Safety & Integrity Officer, Energy, Picarro, Inc.	February 2020 to August 2020
		Senior positions within the Utility including Vice President, Asset, Risk Management and Community Wildfire Safety Program from May 2019 to January 2020, Vice President, Community Wildfire Safety Program, from September 2018 to May 2019, Vice President, Gas Asset and Risk Management from September 2015 to August 2018	September 2015 to January 2020
John R. Simon	57	Executive Vice President, General Counsel and Chief Ethics & Compliance Officer	August 15, 2020 to present
		Executive Vice President, Law, Strategy, and Policy	June 2019 to August 2020
		Executive Vice President	May 2019 to June 2019
		Interim Chief Executive Officer	January 2019 to May 2019
		Executive Vice President and General Counsel	March 2017 to January 2019
		Executive Vice President, Corporate Services and Human Resources	August 2015 to February 2017
Adam L. Wright	44	Executive Vice President, Operations and Chief Operating Officer, Pacific Gas and Electric Company	February 1, 2021 to present
		Chief Executive Officer and President, MidAmerican Energy Company	January 2018 to January 26, 2021
		President of MidAmerican Funding LLC	January 2018 to January 26, 2021
		Vice President, Gas Delivery, MidAmerican Energy Company	May 2015 to January 2018
		Vice President, Wind Generation & Development, MidAmerican Energy Company	January 2012 to May 2015
Marlene M. Santos	61	Executive Vice President and Chief Customer Officer, Pacific Gas and Electric Company	March 15, 2021 to present
		President, Gulf Power Company	January 2019 to March 2021
		Chief Integration Officer, NextEra Energy, Inc.	March 2015 to December 2018
Jason M. Glickman	41	Executive Vice President, Engineering, Planning, and Strategy, Pacific Gas and Electric Company	May 3, 2021 to present
		Global Head of Utilities and Renewables, Bain & Company	March 2020 to April 2021
		Partner, Bain & Company	January 2014 to April 2021
		Consultant, Bain & Company	August 2007 to December 2013

The following individuals serve as executive officers of the Utility as of February 10, 2022. Except as otherwise noted, all positions have been held at the Utility.

Adam L. Wright	44	Executive Vice President, Operations and Chief Operating Officer	February 1, 2021 to present
		Chief Executive Officer and President, MidAmerican Energy Company	January 2018 to January 26, 2021
		President of MidAmerican Funding LLC	January 2018 to January 26, 2021
		Vice President, Gas Delivery, MidAmerican Energy Company	May 2015 to January 2018
		Vice President, Wind Generation & Development, MidAmerican Energy Company	January 2012 to May 2015
Marlene M. Santos	61	Executive Vice President and Chief Customer Officer	March 15, 2021 to present
		President, Gulf Power Company	January 2019 to March 2021
		Chief Integration Officer, NextEra Energy, Inc.	March 2015 to December 2018
Jason M. Glickman	41	Executive Vice President, Engineering, Planning, and Strategy	May 3, 2021 to present
		Global Head of Utilities and Renewables, Bain & Company	March 2020 to April 2021
		Partner, Bain & Company	January 2014 to April 2021
		Consultant, Bain & Company	August 2007 to December 2013
David S. Thomason	46	Vice President, Chief Financial Officer, and Controller, Pacific Gas and Electric Company	June 2016 to present
		Vice President and Controller, PG&E Corporation	June 2016 to present
		Senior Director, Financial Forecasting and Analysis	March 2015 to May 2016
		Senior Director, Corporate Accounting	March 2014 to March 2015
Julius Cox	50	Executive Vice President, People, Shared Services and Supply Chain, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2021 to present
		Senior Vice President & Chief Human Resources Officer, American Electric Power	October 2019 to January 2021
		Executive Vice President & Chief Transformation Officer, Dynegy Inc.	September 2017 to April 2018
		Executive Vice President & Chief Administrative Officer, Dynegy Inc.	October 2014 to September 2017
Sumeet Singh	43	Executive Vice President, Chief Risk Officer and Chief Safety Officer, PG&E Corporation and Pacific Gas and Electric Company	January 1, 2022 to present
		Senior Vice President and Chief Risk Officer, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2021 to December 31, 2021
		Interim President and Chief Risk Officer, Pacific Gas and Electric Company; Senior Vice President and Chief Risk Officer, PG&E Corporation	January 1, 2021 to January 31, 2021

Senior Vice President and Chief Risk Officer, PG&E Corporation and Pacific Gas and Electric Company	August 2020 to December 31, 2021
Gas Safety & Integrity Officer, Energy, Picarro, Inc.	February 2020 to August 2020
Senior positions within the Utility including Vice President, Asset, Risk Management and Community Wildfire Safety Program from May 2019 to January 2020, Vice President, Community Wildfire Safety Program, from September 2018 to May 2019, Vice President, Gas Asset and Risk Management from September 2015 to August 2018	September 2015 to January 2020

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 4, 2022, there were 45,223 holders of record of PG&E Corporation common stock. A substantially greater number of holders of PG&E Corporation common stock are "street name" or beneficial holders, whose shares of record are held by banks, brokers, and other financial institutions. PG&E Corporation common stock is listed on the New York Stock Exchange and is traded under the symbol "PCG." Shares of common stock of the Utility are wholly owned by PG&E Corporation. 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 February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, payable on May 13, 2022, to holders of record on April 29, 2022 and declared a dividend on the Utility's preferred stock totaling $3.5 million that will be accrued during the three-month period ending April 30, 2022, payable on May 15, 2022, to holders of record on April 29, 2022. See "Liquidity and Financial Resources - Dividends" in Item 7. MD&A and PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 6 of the Notes to the Consolidated Financial Statements in Item 8. Information about the frequency and amount of dividends declared on preferred stock by the Utility appears in Note 7 of the Notes to the Consolidated Financial Statements in Item 8.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2021, PG&E Corporation did not make any equity contributions to the Utility. Also, PG&E Corporation did not make any sales of unregistered securities during the fiscal year ended December 31, 2021 that were not previously disclosed in a quarterly report on Form 10-Q or a current report on Form 8-K.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2021, PG&E Corporation did not redeem or repurchase any shares of common stock or equity units outstanding. PG&E Corporation does not have any preferred stock outstanding. Also, during the quarter ended December 31, 2021, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. SELECTED FINANCIAL DATA

Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in Item 8.

Summary of Changes in Net Income and Earnings per Share

PG&E Corporation's net loss attributable to common shareholders was $102 million in 2021, compared to $1.3 billion in 2020. In the year ended December 31, 2021, PG&E Corporation recorded a $1.3 billion charge, net of tax as a result of the grantor trust election, with no similar amount in 2020. This amount is partially offset by increases in base revenues authorized in the 2020 GRC and previously deferred costs associated with various regulatory proceedings in the year ended December 31, 2021. In the year ended December 31, 2020, PG&E Corporation recognized $1.1 billion of expense related to the Backstop Commitment Premium Shares and $452 million of expense related to the Additional Backstop Premium Shares, with no similar amounts in 2021.

Key Factors Affecting Financial Results

PG&E Corporation and the Utility believe that their financial condition, results of operations, liquidity, and cash flows may be materially affected by the following factors:

- *The Uncertainties in Connection with Any Future Wildfires, Wildfire Insurance, and AB 1054.* While PG&E Corporation and the Utility cannot predict the occurrence, timing or extent of damages in connection with future wildfires, factors such as environmental conditions (including weather and vegetation conditions) and the efficacy of wildfire risk mitigation initiatives are expected to influence the frequency and severity of future wildfires. To the extent that future wildfires occur in the Utility's service territory, the Utility may incur costs associated with the investigations of the causes and origins of such fires, even if it is subsequently determined that such fires were not caused by the Utility's facilities. The financial impact of future wildfires could be mitigated through insurance, the Wildfire Fund or other forms of cost recovery. However, the Utility may not be able to obtain sufficient wildfire insurance coverage at a reasonable cost, or at all, and any such coverage may include limitations that could result in substantial uninsured losses depending on the amount and type of damages resulting from covered events, including coverage limitations applicable to different insurance layers. The Utility will not be able to obtain any recovery from the Wildfire Fund for wildfire-related losses in any Wildfire Fund coverage year ("Coverage Year") that do not exceed the greater of $1.0 billion in the aggregate and the amount of insurance coverage required under AB 1054. In addition, the policy reforms contemplated by AB 1054 are likely to affect the financial impact of future wildfires on PG&E Corporation and the Utility should any such wildfires occur. The Wildfire Fund is available to the Utility to pay eligible claims for liabilities arising from wildfires and serves as an alternative to traditional insurance products, provided that the Utility satisfies the conditions to the Utility's ongoing participation in the Wildfire Fund set forth in AB 1054 and that the Wildfire Fund has sufficient remaining funds. See "Loss Recoveries" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

  However, the impact of AB 1054 on PG&E Corporation and the Utility is subject to numerous uncertainties, including the Utility's ability to demonstrate to the CPUC that wildfire-related costs paid from the Wildfire Fund were just and reasonable and therefore not subject to reimbursement, and whether the benefits of participating in the Wildfire Fund ultimately outweigh its substantial costs. Finally, even if the Utility satisfies the ongoing eligibility and other requirements set forth in AB 1054, for eligible claims against the Utility arising from wildfires that occurred between July 12, 2019 and the Utility's emergence from Chapter 11 on July 1, 2020, the availability of the Wildfire Fund to pay such claims would be capped at 40% of the allowed amount of such claims. See "Wildfire Fund under AB 1054" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

- *The Costs, Effectiveness, and Execution of the Utility's Wildfire Mitigation Initiatives.* In response to the wildfire threat facing California, PG&E Corporation and the Utility have taken aggressive steps to mitigate the threat of catastrophic wildfires, the spread of wildfires should they occur and the impact of PSPS events.

  PG&E Corporation and the Utility incurred substantial expenditures in 2020 and 2021 in connection with the 2020-2022 WMP. For more information, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8. The Utility expects that its wildfire mitigation initiatives will continue to involve substantial and ongoing expenditures. The extent to which the Utility will be able to recover these expenditures and potential other costs through rates is uncertain.

  The Utility has implemented operational changes and investments that reduce wildfire risk, including the EPSS, PSPS, vegetation management, asset inspection, and system hardening programs. These programs, particularly the PSPS and EPSS programs, have been the subject of significant scrutiny and criticism by various stakeholders, including the California governor, the CPUC and the court that oversaw the Utility's probation. The PSPS and EPSS programs have had an adverse impact on PG&E Corporation's and the Utility's reputation with customers, regulators and policymakers, and future PSPS events may increase these negative perceptions. See "OII to Examine the Late 2019 Public Safety Power Shutoff Events" in "Regulatory Matters" below.

  The Utility is subject to a number of legal and regulatory requirements related to its wildfire mitigation efforts, which require periodic inspections of electric assets and ongoing reporting related to this work. Although the Utility believes that it has complied substantially with these requirements, it is undertaking a review and has identified instances of noncompliance. The Utility intends to update the CPUC and OEIS as its review progresses. The Utility could face fines, penalties, enforcement action, or other adverse legal or regulatory consequences for the late inspections or other noncompliance related to wildfire mitigation efforts. See "Self-Reports to the CPUC" in "Regulatory Matters" below.

While PG&E Corporation and the Utility are committed to taking aggressive wildfire mitigation actions, if additional requirements are imposed that go beyond current expectations, such requirements could have a substantial impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. The success of the Utility's wildfire mitigation efforts depends on many factors, including on whether the Utility is able to retain or contract for the workforce necessary to execute its wildfire mitigation actions. See "Order Instituting Investigation into the 2017 Northern California Wildfires and the 2018 Camp Fire" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

- *The Timing and Outcome of Ratemaking Proceedings.* The Utility's financial results may be impacted by the timing and outcome of its FERC TO18 rate case and the resulting impact on the TO19 and TO20 rate cases, 2023 GRC, WMCE applications, and its ability to timely recover costs not currently in rates, including costs already incurred and future costs tracked in its CEMA, WEMA, WMPMA, FRMMA, CPPMA, VMBA, WMBA, and RTBA. The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potential rate impacts, the regulatory and political environments, and other factors. See Notes 4 and 15 of the Notes to the Consolidated Financial Statements in Item 8 and "Regulatory Matters" below.

- *The Impact of Wildfires*. PG&E Corporation's and the Utility's liabilities for the 2019 Kincade fire, the 2020 Zogg fire, or the 2021 Dixie fire, are significant and may be excluded from any potential amounts recoverable under applicable insurance policies, the WEMA, FERC TO rates, or the Wildfire Fund under AB 1054. Recorded liabilities in connection with the 2019 Kincade fire and the 2021 Dixie fire have already exceeded potential amounts recoverable under applicable insurance policies. Liabilities in excess of recoverable amounts for these wildfires could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

  As of December 31, 2021, PG&E Corporation and the Utility had recorded an aggregate liability of $800 million, $375 million, and $1.15 billion for claims in connection with the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire, respectively, and in each case before available insurance and other probable cost recoveries in the case of the 2021 Dixie fire. These liability amounts correspond to the lower end of the range of reasonably estimable probable losses, but do not include all categories of potential damages and losses. Claims related to the 2019 Kincade fire that were not satisfied in full as of the Emergence Date were not discharged in connection with emerging from Chapter 11.

  On April 6, 2021, the Sonoma County District Attorney's Office charged the Utility with five felonies and 28 misdemeanors in connection with the 2019 Kincade fire, and on January 28, 2022, the Sonoma County District Attorney's Office filed the Kincade Amended Complaint, which replaced two felonies with five different felonies and dropped six misdemeanor counts. On September 24, 2021, the Shasta County District Attorney's Office charged the Utility with 11 felonies and 20 misdemeanors in connection with the 2020 Zogg fire and three other fires. If the Utility were to be convicted of certain charges in the Kincade Amended Complaint or the Zogg Complaint, the Utility could be subject to material fines, penalties, and restitution, as well as non-monetary remedies such as oversight requirements, and accordingly the Utility currently believes that, depending on which charges it were to be convicted of, its total losses associated with the 2019 Kincade fire or the 2020 Zogg fire would materially exceed the $800 million or $375 million, respectively, of aggregate liability that PG&E Corporation and the Utility have recorded.

  If the eligible claims for liabilities arising from wildfires were to exceed $1.0 billion in any Coverage Year, the Utility may be eligible to make a claim to the Wildfire Fund under AB 1054 for such excess amount, except that recoveries for the 2019 Kincade fire would be subject to the 40% limitation on the allowed amount of claims arising before emergence from bankruptcy, and recoveries for each of these fires would also be subject to the other limitations and requirements under AB 1054. As of December 31, 2021, the Utility had recorded insurance receivables of $430 million for the 2019 Kincade fire, $337 million for the 2020 Zogg fire, and $563 million for the 2021 Dixie fire. The Utility had recorded regulatory recovery and Wildfire Fund receivables of $448 million and $150 million, respectively, for the 2021 Dixie fire. However, there can be no assurance that such amounts will ultimately be recovered, and the Utility does not expect that any of its liability insurance would cover restitution payments ordered by the courts presiding over the criminal proceedings. See "2019 Kincade Fire," "2020 Zogg Fire," and "2021 Dixie Fire" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 for more information.

- *The Outcome of Other Enforcement, Litigation, and Regulatory Matters, and Other Government Proposals.* The Utility's financial results may continue to be impacted by the outcome of other current and future enforcement, litigation, and regulatory matters, including those described above as well as the outcome of the Safety Culture OII, and potential penalties in connection with the Utility's WMP and safety and other self-reports. See Note 15 of the Notes to the Consolidated Financial Statements in Item 8. In addition, the Utility's business profile and financial results could be impacted by the outcome of recent calls for municipalization of part or all of the Utility's businesses, offers by municipalities and other public entities to acquire the electric assets of the Utility within their respective jurisdictions and calls for state intervention, including the possibility of a state takeover of the Utility. PG&E Corporation and the Utility cannot predict the nature, occurrence, timing or extent of any such scenario, and there can be no assurance that any such scenario would not involve significant ownership or management changes to PG&E Corporation or the Utility, including by the state of California. Further, certain parties filed notices of appeal with respect to the Confirmation Order, including provisions related to the injunction contained in the Plan that channels certain pre-petition fire-related claims to trusts to be satisfied from the trusts' assets. There can be no assurance that any such appeal will not be successful and, if successful, that any such appeal would not have a material adverse effect on PG&E Corporation and the Utility.

- *The Uncertainties in Connection with the Enhanced Oversight and Enforcement Process.* On April 15, 2021, the CPUC placed the Utility in step 1 of the EOEP. As a result, the Utility is subject to additional reporting requirements, monitoring, and oversight by the CPUC. See "Enhanced Oversight and Enforcement Process" in "Enforcement and Litigation Matters" below.

- *The Impact of the COVID-19 Pandemic.* PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic. The principal areas of near-term impact include liquidity, financial results and business operations, stemming primarily from the ongoing economic hardship of the Utility's customers, the moratorium on service disconnections, and an observed reduction in non-residential electrical load. The Utility continues to monitor the overall impact of the COVID-19 pandemic; however, the Utility expects a significant impact on monthly cash collections as long as current circumstances persist. PG&E Corporation and the Utility expect additional financial impacts in the future as a result of COVID-19 pandemic. Other impacts of COVID-19 pandemic on PG&E Corporation and the Utility have included operational disruptions, workforce disruptions, both in personnel availability (including a reduction in contract labor resources) and deployment, delays in production and shipping of materials used in the Utility's operations, higher credit spreads and borrowing costs and could potentially also include a reduction in revenue due to the cost of capital adjustment mechanism and incremental financing needs. For more information on the impact of COVID-19 pandemic on PG&E Corporation and the Utility, see "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic." in Item 1A Risk Factors and "COVID-19" in Liquidity and Financial Resources below.

For more information about the risks that could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this annual report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See "Forward-Looking Statements" above for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are unable to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

Tax Matters

PG&E Corporation had a U.S. federal net operating loss carryforward of approximately $21.1 billion and California net operating loss carryforward of $18.9 billion at the end of 2021.

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. 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 4.75% or more prior to the Restriction Release Date (as defined in the Amended Articles) without approval by the Board of Directors of PG&E Corporation (the "Ownership Restrictions"). As discussed below under "Update on Ownership Restrictions in PG&E Corporation's Amended Articles," due to the election to treat the Fire Victim Trust as a grantor trust for income tax purposes, the calculation of Percentage Stock Ownership (as defined in the Amended Articles) will effectively be based on a reduced number of shares outstanding, namely the total number of outstanding equity securities less the number of equity securities held by the Fire Victim Trust, the Utility and ShareCo. 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.

On July 8, 2021, PG&E Corporation, the Utility, ShareCo and the Fire Victim Trust entered into the Share Exchange and Tax Matters Agreement, pursuant to which PG&E Corporation and the Utility made a grantor trust election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust.

As a result of the benefits of a grantor trust election, the Utility's tax deductions occur when the Fire Victim Trust pays the fire victims, rather than when the Utility transferred cash and other property (including PG&E Corporation common stock) to the Fire Victim Trust. Therefore, $5.4 billion of cash and $4.54 billion of PG&E Corporation common stock, in the aggregate $10.0 billion, that were transferred to the Fire Victim Trust in 2020, will not be deductible for tax purposes by the Utility until the Fire Victim Trust pays the fire victims.

Furthermore, the activities of the Fire Victim Trust are treated as activities of the Utility for tax purposes. PG&E Corporation's net operating loss has decreased by approximately $10.0 billion which will be offset by payments made by the Fire Victim Trust to the fire victims (which totaled approximately $1.67 billion in 2021) and the net activities of the Fire Victim Trust. Additionally, there was a $1.3 billion charge, net of tax, decreasing net DTAs for the payment made to the Fire Victim Trust in PG&E Corporation common stock on its Consolidated Financial Statements for activity through December 31, 2020. PG&E Corporation will recognize income tax benefits and the corresponding DTA as the Fire Victim Trust sells shares of PG&E Corporation common stock, and the amounts of such benefits and assets 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 transferred to the Fire Victim Trust. As of December 31, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock, resulting in no tax impact on PG&E Corporation's and the Utility's Consolidated Financial Statements for the year ended December 31, 2021. On January 31, 2022, the Fire Victim Trust initiated an exchange of 40,000,000 Plan Shares for an equal number of New Shares in the manner contemplated by the Share Exchange and Tax Matters Agreement and announced that it had entered into a transaction for the sale of these shares.

Update on Ownership Restrictions in PG&E Corporation's Amended Articles

As a result of the grantor trust election, shares of PG&E Corporation common stock owned by the Fire Victim Trust are treated as held by the Utility and, in turn, attributed to PG&E Corporation for income tax purposes. Consequently, any shares of PG&E Corporation common stock owned by the Fire Victim Trust, along with any shares owned by the Utility directly, are effectively excluded from the total number of outstanding equity securities when calculating a person's Percentage Stock Ownership (as defined in the Amended Articles) for purposes of the 4.75% ownership limitation in the Amended Articles. Shares owned by ShareCo are also effectively excluded because ShareCo is a disregarded entity for income tax purposes. For example, although PG&E Corporation had 2,463,891,104 shares outstanding as of February 4, 2022, only 1,548,403,924 shares (the number of outstanding shares of common stock less the number of shares held by the Fire Victim Trust, the Utility and ShareCo) count as outstanding for purposes of the ownership restrictions in the Amended Articles. As such, based on the total number of outstanding equity securities and assuming the Fire Victim Trust has not sold any shares of PG&E Corporation common stock, a person's effective Percentage Stock Ownership limitation for purposes of the Amended Articles as of February 4, 2022 was 2.98% of outstanding shares. As of December 31, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock. On January 31, 2022, the Fire Victim Trust initiated an exchange of 40,000,000 Plan Shares for an equal number of New Shares in the manner contemplated by the Share Exchange and Tax Matters Agreement and announced that it had entered into a transaction for the sale of these shares.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2021, 2020, and 2019. See "Key Factors Affecting Financial Results" above for further discussion about factors that could affect future results of operations.

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders:

(in millions)	2021	2020	2019
Consolidated Total	$ (102)	$ (1,318)	$ (7,656)
PG&E Corporation	(226)	(1,715)	(20)
Utility	124	397	(7,636)

PG&E Corporation's net loss decreased in 2021, as compared to 2020 and primarily consists of income taxes, interest expense on long-term debt, and reorganization items, net. PG&E Corporation's net loss for the year ended December 31, 2020 included $1.5 billion in expense related to the Backstop Commitment Premium Shares and Additional Backstop Premium Shares, which is not deductible for tax purposes.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2021, 2020, and 2019. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

	2021			2020			2019		
	Revenues and Costs:			Revenues and Costs:			Revenues and Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 9,542	$ 5,589	$ 15,131	$ 8,979	$ 4,879	$ 13,858	$ 8,634	$ 4,106	$ 12,740
Natural gas operating revenues	3,753	1,758	5,511	3,460	1,151	4,611	3,259	1,130	4,389
Total operating revenues	**13,295**	**7,347**	**20,642**	**12,439**	**6,030**	**18,469**	**11,893**	**5,236**	**17,129**
Cost of electricity	—	3,232	3,232	—	3,116	3,116	—	3,095	3,095
Cost of natural gas	—	1,149	1,149	—	782	782	—	734	734
Operating and maintenance	6,820	3,374	10,194	6,399	2,308	8,707	7,167	1,583	8,750
Wildfire-related claims, net of insurance recoveries	258	—	258	251	—	251	11,435	—	11,435
Wildfire fund expense	517	—	517	413	—	413	—	—	—
Depreciation, amortization, and decommissioning	3,403	—	3,403	3,469	—	3,469	3,233	—	3,233
Total operating expenses	**10,998**	**7,755**	**18,753**	**10,532**	**6,206**	**16,738**	**21,835**	**5,412**	**27,247**
Operating income (loss)	**2,297**	**(408)**	**1,889**	**1,907**	**(176)**	**1,731**	**(9,942)**	**(176)**	**(10,118)**
Interest income	22	—	22	39	—	39	82	—	82
Interest expense	(1,373)	—	(1,373)	(1,111)	—	(1,111)	(912)	—	(912)
Other income, net	104	408	512	294	176	470	63	176	239
Reorganization items, net	(12)	—	(12)	(310)	—	(310)	(320)	—	(320)
Income (loss) before income taxes	$ 1,038	$ —	$ 1,038	$ 819	$ —	$ 819	$ (11,029)	$ —	$ (11,029)
Income tax provision (benefit) (1)			900			408			(3,407)
Net income (loss)			138			411			(7,622)
Preferred stock dividend requirement (1)			14			14			14
Income (loss) Attributable to Common Stock			**$ 124**			**$ 397**			**$ (7,636)**

(1) These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2021, 2020, and 2019, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $856 million, or 7%, in 2021 compared to 2020, primarily due to increased base revenues authorized in the 2020 GRC and FERC formula rates.

The Utility's electric and natural gas operating revenues that impacted earnings increased by $546 million, or 5%, in 2020 compared to 2019, primarily due to increased base revenues authorized in the 2020 GRC and 2019 GT&S rate cases, additional revenues recorded pursuant to the TO20 rate case, and CEMA interim rate relief.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $421 million, or 7%, in 2021 compared to 2020, primarily due to increases in labor and insurance costs as well as a $135 million charge related to wildfire response and mitigation regulatory matters, including the 2020 WMCE settlement. These increases were partially offset by $298 million in previously deferred CEMA costs recorded in conjunction with interim rate relief in 2020, with no comparable costs in 2021.

The Utility's operating and maintenance expenses that impacted earnings decreased by $768 million, or 11%, in 2020 compared to 2019, primarily due to a reduction in accelerated transmission inspection and repair costs of approximately $460 million. Additionally, in 2019 the Utility recorded $398 million related to the Wildfires OII settlement and $237 million in disallowed costs for previously incurred capital expenditures in excess of adopted amounts in the 2019 GT&S rate case in 2019, with no similar charges in 2020. These decreases were partially offset by an increase of $223 million in previously deferred CEMA costs recorded in conjunction with interim rate relief (see "2018 CEMA Application" below) (the Utility amortized $298 million in deferred CEMA costs in 2020, compared to $75 million amortized in 2019). The Utility also experienced increased insurance premium costs in the year ended December 31, 2020, compared to 2019.

Wildfire-Related Claims, Net of Recoveries

Costs related to wildfires that impacted earnings increased by $7 million, or 3%, in 2021 compared to 2020. The Utility recognized pre-tax charges of $1.15 billion related to the 2021 Dixie fire, offset by $563 million of probable insurance recoveries, $347 million of probable recoveries through the WEMA, and $150 million of probable recoveries from the Wildfire Fund in 2021, with no comparable charges and recoveries in 2020. The Utility recognized pre-tax charges of $175 million related to the 2019 Kincade fire in the year ended December 31, 2021, as compared to $625 million, partially offset by $430 million of probable insurance recoveries in the year ended December 31, 2020. Additionally, the Utility recognized pre-tax charges of $100 million related to the 2020 Zogg fire, fully offset by $100 million of probable insurance recoveries, in the year ended December 31, 2021, as compared to pre-tax charges of $275 million, partially offset by $219 million of probable insurance recoveries in the year ended December 31, 2020.

In addition to the probable wildfire-related recoveries noted above, in 2021, the Utility recorded $101 million of probable recoveries through FERC TO formula rates, which are recorded as a reduction to regulatory liabilities and are not captured in wildfire-related claims, which along with the items noted above, fully offset the $1.15 billion charge related to the 2021 Dixie fire.

Costs related to wildfires that impacted earnings decreased by $11.2 billion, or 98%, in 2020 compared to 2019. The Utility recognized pre-tax charges of $625 million related to the 2019 Kincade fire, partially offset by $430 million of probable insurance recoveries, and pre-tax charges of $275 million related to the 2020 Zogg fire, partially offset by $219 million of probable insurance recoveries in 2020. The Utility recognized charges of $11.4 billion in 2019, for wildfire-related claims primarily associated with the 2018 Camp fire and 2017 Northern California wildfires.

See Item 1A. Risk Factors and Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Wildfire Fund Expense

Wildfire fund expense that impacted earnings increased by $104 million, or 25%, in 2021 compared to 2020. Due to the Chapter 11 Cases, the Utility's participation in the Wildfire Fund was limited to 40% for the period from July 12, 2019 to June 30, 2020. Additionally, the Utility recorded $43 million of accelerated amortization as a result of the Wildfire Fund receivable accrued in relation to the 2021 Dixie fire.

Wildfire fund expense that impacted earnings increased by $413 million, or 100%, in 2020 compared to 2019. In 2020, the Utility became eligible to participate in the Wildfire Fund and as a result recorded amortization and accretion expense related to the Wildfire Fund coverage received from the effective date of AB 1054 through December 31, 2020.

See Notes 3 and 14 of the Notes to the Consolidated Financial Statements in Item 8.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses decreased by $66 million, or 2%, in 2021 compared to 2020, primarily due to a reduction in decommissioning expense that was recorded as a result of the final 2018 Nuclear Decommissioning Cost Triennial Proceeding decision.

The Utility's depreciation, amortization, and decommissioning expenses increased by $236 million, or 7%, in 2020 compared to 2019, primarily due to capital additions and an increase in depreciation rates associated with the TO20 decision.

Interest Income

The Utility's interest income that impacted earnings decreased by $17 million, or 44%, in 2021 compared to 2020. Interest income decreased by $43 million, or 52%, in 2020 compared to 2019. The Utility's interest income is primarily affected by changes in regulatory balancing accounts and changes in interest rates.

Interest Expense

Interest expense that impacted earnings increased by $262 million, or 24%, in 2021 compared to 2020, primarily due to the issuance of additional long-term debt.

The Utility's interest expense that impacted earnings increased by $199 million, or 22%, in 2020 compared to 2019, primarily due to the issuance of new debt in 2020 in connection with the emergence from Chapter 11.

Other Income, Net

Changes to Other income, net that impact earnings are primarily driven by fluctuations in the balance of construction work in progress that impact equity AFUDC.

Reorganization Items, Net

Reorganization items, net that impacted earnings decreased by $298 million, or 96%, in 2021 compared to 2020, primarily due to the Utility's emergence from the Chapter 11 Cases on July 1, 2020.

There was no material change to reorganization items, net that impacted earnings in 2020 compared to 2019.

Income Tax Provision (Benefit)

Income tax expense increased by $492 million in 2021 compared to 2020, primarily due to a DTA write-off associated with the grantor trust election for the Fire Victim Trust in 2021, as compared to a smaller DTA write-off associated with the decline in value of PG&E Corporation common stock contributed into a Fire Victim Trust in the same period in 2020.

The Utility's income tax benefit increased by $3.8 billion in 2020 compared to 2019, primarily due to a pre-tax loss in 2019 compared to pre-tax income in 2020. Additionally, there was a $619 million adjustment from the measurement of the DTA 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 in 2020.

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

	2021	2020	2019
Federal statutory income tax rate	21.0 %	21.0 %	21.0 %
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit) [1]	24.1 %	19.1 %	7.5 %
Effect of regulatory treatment of fixed asset differences [2]	(51.6) %	(44.9) %	2.8 %
Tax credits	(1.2) %	(1.7) %	0.1 %
Fire Victim Trust [3]	91.9 %	51.7 %	— %
Bankruptcy and emergence	— %	2.4 %	— %
Other, net [4]	2.6 %	2.2 %	(0.5) %
Effective tax rate	**86.8 %**	**49.8 %**	**30.9 %**

(1) Includes the effect of state flow-through ratemaking treatment and the effect of the grantor trust election.

(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 2021 and 2020, 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) Includes the effect of the grantor trust election as discussed in Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

(4) These amounts primarily represent the impact of tax audit settlements and non-tax deductible penalty costs in 2021 and 2020.

Utility Revenues and Costs that did not Impact Earnings

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs. See below for more information.

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), fuel and associated transmission costs used in its own generation facilities, fuel and associated transmission costs supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. Cost of electricity also includes net sales (Utility owned generation and third parties) in the CAISO electricity markets. See Note 10 of the Notes to the Consolidated Financial Statements in Item 8. The Utility's total purchased power is driven by customer demand, net CAISO electricity market activities (purchases or sales), the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

(in millions)	2021	2020	2019
Cost of purchased power, net	$ 2,883	$ 2,854	$ 2,809
Fuel used in own generation facilities	349	262	286
Total cost of electricity	**$ 3,232**	**$ 3,116**	**$ 3,095**

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage and transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. See Note 10 of the Notes to the Consolidated Financial Statements in Item 8. The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

(in millions)	2021	2020	2019
Cost of natural gas sold	$ 1,010	$ 648	$ 622
Transportation cost of natural gas sold	139	134	112
Total cost of natural gas	**$ 1,149**	**$ 782**	**$ 734**

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings.

Other Income, Net

The Utility's other income, net that did not impact earnings includes pension and other post-retirement benefit costs that fluctuate primarily from market and interest rate changes.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations, finance capital expenditures, make scheduled principal and interest payments, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes retained earnings, equity contributions from PG&E Corporation and long-term debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock and relies on short-term debt, including its revolving credit facilities, to fund temporary financing needs. 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.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, and fund equity contributions to the Utility depends on the level of cash on hand, cash received from the Utility, and PG&E Corporation's access to the capital and credit markets.

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters. Credit rating downgrades may impact the cost and availability of short-term borrowings, including credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. The collateral posting provisions for some of the Utility's power and natural gas commodity, and transportation and service agreements state that if the Utility's credit ratings were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some or all of its net liability positions. The Utility's credit ratings fell below investment grade in January 2019, at which time the Utility was required to post additional collateral under its commodity purchase agreements. A further downgrade would not materially impact the collateral postings for procurement activity. See Note 10 of the Notes to the Consolidated Financial Statements in Item 8.

PG&E Corporation and the Utility have various contractual commitments which impact cash requirements. These commitments are discussed in "Recognition of Lease Assets and Liabilities" in Note 3, Note 5, Note 12, and "Purchase Commitments" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

COVID-19

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic. The outbreak of the COVID-19 pandemic, the emergence of variant strains of the virus (including Delta and Omicron), and the resulting economic conditions and government orders have had and will continue to have a significant adverse impact on the Utility's customers and, as a result, these circumstances have impacted and will continue to impact the Utility for an indeterminate period of time. The principal areas of near-term impact include liquidity, financial results and business operations, stemming primarily from the ongoing economic hardship of the Utility's customers, the moratorium on service disconnections for residential and small business customers and for eligible medium and large commercial and industrial customers that expired on September 30, 2021, the CPUC's "Emergency Authorization and Order Directing Utilities to Implement Emergency Customer COVID-19 Protections" and an observed reduction in non-residential electrical load. The Utility's accounts receivable balances over 30 days outstanding as of December 31, 2021, were approximately $1.1 billion, or $832 million higher as compared to the balance as of December 31, 2019. The Utility is unable to estimate the portion of the increase directly attributable to the COVID-19 pandemic. The Utility expects to continue experiencing an impact on monthly cash collections for as long as current COVID-19 circumstances persist.

On April 16, 2020, the CPUC adopted a resolution ordering utilities to implement a number of emergency customer protections, including a moratorium on service disconnections for residential and small business customers, beginning on March 4, 2020, which it subsequently extended through June 30, 2021. The CPUC authorized utilities to establish memorandum accounts to track incremental costs associated with complying with the resolution. On April 19, 2021, the CPUC issued a final decision to implement a temporary moratorium on service disconnection for medium and large commercial and industrial customers. Although the moratorium on service disconnections ended on September 30, 2021, the Utility does not anticipate resuming service disconnections until 2022. If the moratorium on service disconnections were to be reinstated, it could have a material impact on results of operations, financial condition, and cash flows of PG&E Corporation and the Utility.

Although the Utility is seeking further regulatory relief to mitigate the impact of the consequences of the COVID-19 pandemic, there can be no assurance as to the amount or timing of such relief. On July 16, 2021, the California governor signed into law AB 135, which provides financing assistance to customer accounts in arrears. See "Assembly Bill 135" below for more information. AB 135 allocates roughly $300 million in relief funding to the Utility's customers and the amount was paid on January 27, 2022.

As of December 31, 2021, PG&E Corporation and the Utility had access to approximately $2.2 billion of total liquidity comprised of approximately $165 million of Utility cash, $126 million of PG&E Corporation cash and $1.9 billion of availability under PG&E Corporation's and the Utility's revolving credit facilities. The 2022 cost of capital application was filed off-cycle based on the extraordinary event of the COVID-19 pandemic and related government response. See "Cost of Capital Proceedings" below for more information.

The Utility has established the CPPMA memorandum accounts for tracking costs related to the CPUC's emergency authorization and order, which, as of December 31, 2021, totaled $49 million and is reflected in Long-term regulatory assets on the Consolidated Balance Sheets. In addition to the $49 million recorded to the CPPMA that is subject to CPUC approval, the Utility has recorded approximately $127 million of undercollections from residential customers from June 11, 2020 to December 31, 2021 to the RUBA, which has been approved by the CPUC and is reflected in Regulatory balancing accounts receivable on the Consolidated Balance Sheets. During the quarter ended December 31, 2021, there was an adjustment to the RUBA current balancing accounts receivable of $180 million as a result of the expected CAPP funding, which was received on January 27, 2022. For more information on the impact of the COVID-19 pandemic on PG&E Corporation and the Utility, see "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows have been and could continue to be significantly affected by the outbreak of the COVID-19 pandemic" in Item 1A. Risk Factors in Part I of this 2021 Form 10-K.

The COVID-19 pandemic may continue to impact PG&E Corporation and the Utility financially, and PG&E Corporation and the Utility will continue to monitor the overall impact of the COVID-19 pandemic.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds.

Financial Resources

Equity Financings

On April 30, 2021, PG&E Corporation entered into an Equity Distribution Agreement with the Agents, the Forward Sellers and the Forward Purchasers (each as defined in "At the Market Equity Distribution Program" in Note 6 of the Notes to the Consolidated Financial Statements in Item 8), establishing an at the market equity distribution program, pursuant to which PG&E Corporation, through the Agents, may offer and sell from time to time shares of PG&E Corporation's common stock having an aggregate gross sales price of up to $400 million. The Equity Distribution Agreement provides that, in addition to the issuance and sale of shares of common stock by PG&E Corporation to or through the Agents, PG&E Corporation may enter into Forward Sale Agreements (as defined in "At the Market Equity Distribution Program" in Note 6 of the Notes to the Consolidated Financial Statements in Item 8) with the Forward Purchasers.

As of December 31, 2021, there was $400 million available under PG&E Corporation's at the market equity distribution program for future offerings. During the year ended December 31, 2021, PG&E Corporation has not sold any shares pursuant to the Equity Distribution Agreement or any Forward Sale Agreement.

Debt Financings

In March 2021, the Utility issued (i) $1.5 billion aggregate principal amount of 1.367% First Mortgage Bonds due March 10, 2023, (ii) $450 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031, and (iii) $450 million aggregate principal amount of 4.20% First Mortgage Bonds due June 1, 2041. The proceeds were used for (i) the prepayment of all of the $1.5 billion 364-day term loan facility (maturing June 30, 2021) outstanding under the Utility Term Loan Credit Agreement, (ii) the repayment of all of the borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement, and (iii) general corporate purposes.

In June 2021, the Utility issued $800 million aggregate principal amount of 3.0% First Mortgage Bonds due June 15, 2028. The proceeds were used for general corporate purposes, including the repayment of borrowings under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

On November 15, 2021, the Utility completed the sale of (i) $300 million aggregate principal amount of Floating Rate First Mortgage Bonds due November 14, 2022, (ii) $900 million aggregate principal amount of 1.70% First Mortgage Bonds due November 15, 2023 and (iii) an additional $550 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031 (the "2031 Bonds"). The 2031 Bonds are part of the same series of debt securities issued by the Utility in March 2021. The proceeds were used for the repayment of the $1.45 billion aggregate principal amount of the Utility's Floating Rate First Mortgage Bonds due November 15, 2021. The Utility used the remaining net proceeds for general corporate purposes, including the repayment of approximately $300 million of borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

For more information, see "Recovery Bonds" below and "Long-Term Debt" in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

Credit Facilities

As of December 31, 2021, PG&E Corporation and the Utility had $500 million and $1.4 billion available under their respective $500 million and $6.4 billion credit facilities, including the Utility's term loan credit facility and Receivables Securitization Program. The amount the Utility may borrow under the Receivables Securitization Program is limited to the lesser of the facility limit and the facility availability. The facility availability may vary based on the amount of accounts receivable that the Utility owns that are eligible for sale to the SPV and the portion of those accounts receivable that are sold to the SPV that are eligible for advances by the lenders under the Receivables Securitization Program from time to time.

For more information, see "Credit Facilities" in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

Intercompany Note Payable

On August 11, 2021, PG&E Corporation borrowed $145 million from the Utility under an interest bearing 364-day intercompany note due August 10, 2022. The intercompany note includes usual and customary provisions for notes of this type. The interest rate on the loan is a variable rate equal to the interest rate applicable to loans under the Corporation Revolving Credit Agreement. Interest is due on the last business day of each month, commencing on August 31, 2021. The proceeds were borrowed to fund debt service obligations of PG&E Corporation. As of December 31, 2021, the intercompany note is reflected in Accounts receivable - other on the Utility's Consolidated Balance Sheet and is eliminated upon consolidation of PG&E Corporation's Consolidated Balance Sheet.

Recovery Bonds

On November 12, 2021, PG&E Recovery Funding LLC, a bankruptcy remote, limited liability company wholly owned by the Utility, issued approximately $860 million of senior secured recovery bonds. The recovery bonds were issued in three tranches: (1) approximately $266 million with an interest rate of 1.46% and is due July 15, 2033, (2) approximately $160 million with an interest rate of 2.28% and is due January 15, 2038, and (3) approximately $434 million with an interest rate of 2.82% and is due July 15, 2048. The net proceeds were used to fund fire risk mitigation capital expenditures that have been incurred by the Utility and incurred by PG&E Corporation on behalf of the Utility in 2020 and 2021.

For more information, see "AB 1054" in Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

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 March 20, 2020, PG&E Corporation and the Utility filed a 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. As of January 31, 2022, there were $59.1 million of such cumulative and unpaid dividends on the Utility's preferred stock. 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. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, payable on May 13, 2022, to holders of record on April 29, 2022 and declared a dividend on the Utility's preferred stock totaling $3.5 million that will be accrued during the three-month period ending April 30, 2022, payable on May 15, 2022, to holders of record on April 29, 2022. It is uncertain as to when PG&E Corporation and the Utility will commence the payment of dividends on their common stock.

Utility Cash Flows

The Utility's cash flows were as follows:

	Year Ended December 31,		
(in millions)	**2021**	**2020**	**2019**
Net cash provided by (used in) operating activities	$ 2,448	$ (19,047)	$ 4,810
Net cash used in investing activities	(7,050)	(7,748)	(6,378)
Net cash provided by financing activities	4,379	26,070	1,395
Net change in cash, cash equivalents, and restricted cash	**$ (223)**	**$ (725)**	**$ (173)**

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2021, net cash provided by operating activities increased by $21.5 billion compared to the same period in 2020. This increase was primarily due to the payment of $18.8 billion in satisfaction of pre-petition wildfire-related claims in 2020 as compared to the payment of $758 million to the Fire Victim Trust in 2021. Additionally, the Utility made initial and first annual contributions to the Wildfire Fund of $5.2 billion during the year ended December 31, 2020 as compared to the $193 million contribution made during the year ended December 31, 2021. Lastly, the Utility paid approximately $260 million more in interest in satisfaction of pre-petition claims during the year ended December 31, 2020 as compared to 2021. The increase was partially offset by wildfire-related insurance reimbursements of $2.2 billion received in 2020 as compared to $0.1 billion in 2021.

During 2020, net cash provided by operating activities decreased by $23.9 billion compared to 2019. This decrease was primarily due to the payment of $18.8 billion in satisfaction of pre-petition wildfire-related claims (including claims associated with the 2018 Camp fire, the 2017 Northern California wildfires, and the 2015 Butte fire), and the initial, first, and second annual contributions made to the Wildfire Fund of $5.2 billion, with no similar payments made in 2019.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and amount of costs in connection with the 2019 Kincade fire, the 2020 Zogg fire, and the 2021 Dixie fire, and the timing and amount of any potential related insurance, Wildfire Fund, and regulatory recoveries;

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with current and future enforcement, litigation, and regulatory matters (see “Wildfire-Related Securities Class Action” in Note 14 and “Enforcement Matters” in Note 15 of the Notes to the Consolidated Financial Statements in Item 8 and “Regulatory Matters” below for more information);

- the severity, extent and duration of the global COVID-19 pandemic and its impact on the Utility’s service territory, the ability of the Utility to collect on its customer invoices, the ability of the Utility’s customers to pay their utility bills in full and in a timely manner, the ability of the Utility to offset these effects, including with spending reductions, and the ability of the Utility to recover through rates any losses incurred in connection with the COVID-19 pandemic, as well as the impact of the COVID-19 pandemic on the availability or cost of financing;

- the timing and amounts of available funds to pay eligible claims for liabilities arising from future wildfires;

- the timing and amount of substantially increasing costs in connection with 2020-2022 WMPs and the costs previously incurred in connection with the 2019 WMP that are not currently being recovered through rates (see “Regulatory Matters” below for more information);

- the timing and amount of premium payments related to wildfire insurance (see “Insurance Coverage” in Note 14 of the Notes to the Consolidated Financial Statements in Item 8 for more information);

- the timing of the gain to be returned to customers from the sale of the SFGO and transmission tower wireless licenses and the amounts incurred related to the move to and the leasing of the Lakeside Building; and

- the timing and outcomes of the Utility’s pending and future ratemaking and regulatory proceedings, including the extent to which PG&E Corporation and the Utility are able to recover their costs through regulated rates as recorded in memorandum accounts or balancing accounts, or as otherwise requested.

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed under “Purchase Commitments” in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Investing Activities

Net cash used in investing activities decreased by $698 million during 2021 as compared to the same period in 2020. The decrease was primarily due to the sale of the SFGO, which resulted in net proceeds received of $749 million in September 2021, with no similar receipts in 2020. See “Application to Sell General Office Complex” below for more information.

Net cash used in investing activities increased by $1.4 billion during 2020 as compared to 2019 partially due to the payment of pre-petition vendor payables for capital expenditures as a result of emerging from the Chapter 11 Cases. The Utility’s investing activities primarily consist of the construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility’s nuclear generation facilities.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur between $7.8 billion and $8.9 billion in 2022. Additionally, future cash flows used in investing activities will be impacted by the timing and amount related to the intended purchase of the Lakeside Building.

Financing Activities

During 2021, net cash provided by financing activities decreased by $21.7 billion as compared to 2020. This decrease was primarily due to PG&E Corporation making a cash equity contribution to the Utility of approximately $13.0 billion in 2020, with no similar activity in 2021. Additionally, during 2021, the Utility issued approximately $3.3 billion less of long-term debt, net of repayments, as compared to the same period in 2020. In addition, the Utility had net borrowings of $4.6 billion under its credit facilities during the year ended December 31, 2020 as compared to net repayments of $246 million during the same period in 2021. The Utility had net borrowings of short-term debt of $1.4 billion during the year ended December 31, 2020, as compared to net repayments of short-term debt of $1.2 billion during the same period in 2021. The decrease was partially offset by $1.5 billion of net repayments of debtor-in-possession credit facilities in 2020, with no similar payments in 2021. Lastly, the Utility received $370 million of proceeds in 2021 in connection with the Transaction Agreement between the Utility and SBA, with no similar receipts in 2020. For more information, see "Sale of Transmission Tower Wireless Licenses" in Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

During 2020, net cash provided by financing activities increased by $24.7 billion as compared to 2019. This increase was primarily due to PG&E Corporation making a cash equity contribution to the Utility of approximately $13.0 billion, and the Utility receiving $10.4 billion in proceeds from the issuance of short-term and long-term first mortgage bonds, with no similar activities in 2019. Additionally, the Utility had net borrowings of $4.6 billion under its credit facilities during the year ended December 31, 2020, with no similar activity in 2019 due to the Utility entering into the facilities in 2020. These increases were partially offset by net repayments of $1.5 billion on the debtor-in-possession facilities in 2020, as compared to net borrowings of $1.5 billion on the debtor-in-possession facilities in 2019.

Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date or prepayment date of existing debt instruments. Additionally, future cash flows from financing activities will be affected by the timing and outcome of the Utility's applications for a post-emergence securitization transaction and for an AB 1054 securitization transaction. See "Application for Post-Emergence Securitization Transaction" and "Application for AB 1054 Securitization Transaction" below for more information.

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Notes 14 and 15 of the Notes to the Consolidated Financial Statements in Item 8. that are incorporated by reference herein. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

U.S. District Court Matters and Probation

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceeding and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court imposed a sentence on the Utility in connection with the conviction. The court sentenced the Utility to a five-year corporate probation period, oversight by the Monitor for a period of five years, with the ability to apply for early termination after three years, a fine of $3 million to be paid to the federal government, certain advertising requirements, and community service.

In the course of 2021, the court entered numerous other orders, including in connection with the Utility's vegetation management, the Utility's PSPS program, the 2018 Camp fire, the 2019 Kincade fire, the 2020 Zogg fire and the 2021 Dixie fire.

On January 25, 2022, the period of probation expired and the Monitor's oversight of the Utility ended.

Enhanced Oversight and Enforcement Process

In the OII to Consider PG&E Corporation's and the Utility's Plan of Reorganization final decision, the CPUC adopted an EOEP designed to provide a roadmap for how the CPUC will monitor the Utility's operational performance on an ongoing basis. The EOEP contains six steps that are triggered by specific events and includes enhanced reporting requirements and additional monitoring and oversight. These trigger events include failure to obtain an approved WMP, failure to comply with regulatory reporting requirements in the WMP, insufficient progress toward approved safety or risk-driven investments and failure to comply with or demonstrate sufficient progress toward certain metrics (some of which will be determined in an ongoing regulatory proceeding). The EOEP also contains provisions for the Utility to cure and permanently exit the EOEP if it can satisfy specific criteria. If the Utility is placed into the EOEP, actions taken would occur in coordination with the CPUC's existing formal and informal reporting requirements and procedures. The EOEP does not replace or limit the CPUC's regulatory authority, including the authority to issue Orders to Show Cause and Orders Instituting Investigations and to impose fines and penalties. The EOEP requires the Utility to report the occurrence of a triggering event to the CPUC's executive director no later than five business days after the date on which any member of senior management of the Utility becomes aware of the occurrence of a triggering event.

The Utility is unable to predict whether additional fines or penalties may be imposed, or other regulatory actions may be taken.

On August 18, 2021, the President of the CPUC informed the Utility that the CPUC staff intends to conduct a fact-finding review regarding a pattern of self-reported missed inspections and other self-reported safety incidents to determine whether a recommendation to advance the Utility further within the EOEP is warranted.

Vegetation Management

The CPUC placed the Utility into step 1 of the EOEP on April 15, 2021 and imposed additional reporting requirements on the Utility. The CPUC's resolution states that a step 1 triggering event had occurred because the Utility "has made insufficient progress toward approved safety or risk-driven investments related to its electric business." The resolution finds that, based on the CPUC's evaluation of the Utility's EVM work in 2020, the Utility "is not sufficiently prioritizing its Enhanced Vegetation Management ("EVM") based on risk" and "is not making risk-driven investments." The resolution also finds that "less than five percent of the EVM work" the Utility completed in 2020 "was on the 20 highest risk power lines according to [its] own risk rankings."

As required by the CPUC's resolution, the Utility submitted a corrective action plan to the CPUC's Executive Director on May 6, 2021, which is designed to correct or prevent recurrence of the step 1 triggering event, or otherwise mitigate any ongoing safety risk or impact, as soon as practicable, among other things. The corrective action plan addresses the EVM situation that occurred in 2020 and provides a risk-informed EVM workplan for 2021. The Utility is required to update the information contained in the corrective action plan every 90 days. The Utility will remain in step 1 of the EOEP until the CPUC determines that the Utility has met the conditions of the corrective action plan. If the Utility does not adequately meet such conditions within the timeframe approved by the CPUC, the CPUC may place the Utility into a higher step of the EOEP, or the Utility may remain in step 1 of the EOEP if it demonstrates sufficient progress towards meeting such conditions.

The Utility is unable to predict the outcome of this regulatory process.

Order Instituting an Investigation into PG&E Corporation's and the Utility's Safety Culture

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards (the "Safety Culture OII"). The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents.

On June 18, 2019, the CPUC issued a ruling requesting comments from parties on four proposals that it stated may improve the safety culture of PG&E Corporation and the Utility. The four proposals are: separating the Utility into gas and electric utilities (including, as one possibility, sale of the gas assets to a third party); establishing periodic review of the Utility's certificate of convenience and necessity; modifying or eliminating PG&E Corporation's holding company structure; and linking the Utility's rate of return or ROE to safety performance metrics.

On September 4, 2020, the administrative law judge issued a ruling updating case status, which states that the proceeding will remain open as a vehicle to monitor the progress of the Utility in improving its safety culture, and to address any relevant issues that arise, with the CPUC's consultant NorthStar Consulting Group, Inc. continuing in a monitoring role. The ruling states that additional issues may be raised in the proceedings by parties or the CPUC.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of the proceedings described below and other proceedings may materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

During 2021, the Utility continued to make progress on regulatory matters.

- In June, the Utility filed its 2023 GRC application. The application requests a revenue requirement of $15.46 billion for the 2023 test year.

- In August, the CPUC approved the Utility's agreement to sell the SFGO. In September, the sale closed.

- In September, OEIS issued a final decision statement approving the Utility's 2021 WMP, and in October the CPUC ratified the OEIS' approval.

- In September, the Utility filed a motion seeking CPUC approval of a settlement agreement for its 2020 WMCE application. Under the settlement agreement, the Utility would recover a revenue requirement of $1.04 billion, or 81% of the requested $1.28 billion.

- In September, the Utility filed its 2021 WMCE application, requesting cost recovery of approximately $1.6 billion of recorded expenditures related to wildfire mitigation, certain catastrophic events, and a number of other activities, resulting in a proposed revenue requirement of approximately $1.47 billion.

- In October, the CPUC approved the settlement agreement among the Utility and other parties that authorizes the Utility to recover $445.5 million in incremental insurance costs in its WEMA that were incurred for the period of July 26, 2017 through December 31, 2019.

- In November, the Utility filed a motion seeking CPUC approval of a settlement agreement for its 2018 CEMA application. Under the settlement agreement, the Utility would recover approximately $683 million plus interest, compared to the requested $763 million.

In addition, on January 31, 2022, the OEIS issued the Utility's 2021 safety certification, which will be valid for 12 months or until a timely request for a new safety certification is acted upon, whichever occurs later.

Cost Recovery Proceedings

Periodically, costs arise that could not have been anticipated by the Utility during CPUC GRC rate requests or that have been deliberately excluded therefrom. These costs may result from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. The CPUC also authorized balancing accounts with limitations or caps to cost recovery. These accounts, which include the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, and RTBA among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, other wildfire prevention-related costs, certain third-party wildfire claims, and insurance costs. While the Utility generally expects such costs to be recoverable, there can be no assurance that the CPUC will authorize the Utility to recover the full amount of its costs.

In recent years, the amount of the costs recorded in these accounts has increased. As of December 31, 2021, the Utility had recorded an aggregate amount of approximately $5.4 billion in costs not otherwise being recovered in existing revenue requirements, if any, for the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, MGMA, and RTBA. Because rate recovery may require CPUC authorization for these accounts, there is a delay between when the Utility incurs costs and when it may recover those costs.

If the amount of the costs recorded in these accounts continues to increase, the delay between incurring and recovering costs lengthens, or the Utility does not recover the full amount of its costs, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

Except as otherwise noted, the Utility is unable to predict the timing and outcome of the following applications. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to timely recover costs included in these applications.

For more information, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8., "Regulatory Matters - Wildfire Mitigation and Catastrophic Events Costs Recovery Applications," "Regulatory Matters - Application for Recovery of Costs Recorded in the Wildfire Expense Memorandum Account," and "Regulatory Matters - Catastrophic Event Memorandum Accounts and Applications" below.

Wildfire Mitigation and Catastrophic Events Cost Recovery Applications

2020 WMCE Application

On September 30, 2020, the Utility filed an application with the CPUC requesting cost recovery of recorded expenditures related to wildfire mitigation and certain catastrophic events (the "2020 WMCE application"). The recorded expenditures, which exclude amounts disallowed as a result of the CPUC's decision in the OII into the 2017 Northern California wildfires and the 2018 Camp fire, consist of $1.18 billion in expense and $801 million in capital expenditures, resulting in a proposed revenue requirement of approximately $1.28 billion.

The costs addressed in the 2020 WMCE application cover activities mainly during the years 2017 to 2019 and are incremental to those previously authorized in the Utility's 2017 GRC and other proceedings. The Utility's request includes amounts from the FHPMA of $293 million, the FRMMA and the WMPMA of $740 million, and the CEMA of $251 million.

Given the CPUC's prior approval of $447 million in interim rate relief (which includes interest), the Utility proposed to recover the remaining $868 million revenue requirement over a one-year period (following the conclusion of interim rate relief recovery). Cost recovery requested in this application is subject to the CPUC's reasonableness review, which could result in some or all of the interim rate relief being subject to refund.

On September 21, 2021, the Utility and certain parties filed a motion with the CPUC seeking approval of a settlement agreement that would resolve all of the issues raised by the settling parties in the 2020 WMCE application. The settlement agreement proposes that the Utility recover a revenue requirement of $1.04 billion. The settlement agreement would authorize the Utility to continue to recover the interim revenue requirement of $447 million over a 17-month amortization period, followed by an additional revenue requirement of $591 million over a 24-month amortization period. On September 23, 2021, the CPUC extended the statutory deadline for a PD in this matter to April 1, 2022.

2021 WMCE Application

On September 16, 2021, the Utility filed an application with the CPUC requesting cost recovery of approximately $1.6 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.47 billion (the "2021 WMCE application"). The costs addressed in this application reflect costs related to wildfire mitigation and certain catastrophic events, as well as implementation of various customer-focused initiatives. These costs were incurred primarily in 2020.

The recorded expenditures consist of $1.4 billion in expenses and $197 million in capital expenditures. The costs addressed in the 2021 WMCE application are incremental to those previously authorized in the Utility's 2017 GRC, 2020 GRC, and other proceedings. The majority of the Utility's proposed revenue requirement would be collected over a two-year period starting in January 2023.

The Utility's requested revenue requirement includes amounts recorded to the VMBA of $592 million, the CEMA of $535 million, the WMBA of $149 million, and other memo accounts. On November 18, 2021, the Utility filed updates to the application, increasing total costs by $19.4 million. On December 30, 2021, the Utility filed supplemental testimony reducing the cost recovery ask of the COVID-19 CEMA costs by $12.2 million. The $12.2 million reduction is a result of identified avoided costs, such as employee business travel expenses and in-person training costs, due to the pandemic.

The scoping memo shows a schedule with the CPUC issuing a PD in the fourth quarter of 2022.

Wildfire Expense Memorandum Account Application

On February 7, 2020, the Utility filed an application requesting cost recovery of $499 million of insurance premiums paid by the Utility between July 26, 2017 through December 31, 2019, which were recorded in the WEMA. These costs are incremental to the insurance costs authorized in the 2017 GRC. These incremental costs are not associated with any specific wildfire event. The application does not seek recovery of wildfire claims or associated legal costs eligible for recording to the WEMA. On October 21, 2021, the CPUC adopted a final decision approving a settlement agreement among the Utility and the other active parties that authorizes the Utility to recover $445.5 million over a 12-month period beginning January 1, 2022.

Catastrophic Event Memorandum Account Application

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities. The Utility has historically sought such costs through standalone CEMA applications. More recently, the Utility has sought CEMA-eligible costs through its WMCE applications.

In addition to the Utility's responsibilities in responding to catastrophic events, in 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. Through 2019, the costs associated with this work were tracked in the CEMA. In the 2020 GRC decision, the CPUC required the Utility to track these costs in the VMBA beginning January 1, 2020.

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as $405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. The Utility filed three revisions to this application, resulting in a total cost recovery request of $763 million.

On April 25, 2019, the CPUC approved the Utility's request for interim rate relief, allowing for recovery of $373 million of costs as requested by the Utility at that time. The interim rate relief was implemented, commencing on October 1, 2019. Costs included in the interim rate relief are subject to audit and refund.

On November 2, 2021, the Utility filed with the CPUC a settlement agreement with the active parties in the matter. The settlement agreement, if approved by the CPUC, would authorize the Utility to collect a total of $683 million plus interest for the 2018 CEMA application. As noted above, $373 million of the total amount has already been collected in interim rates. The interim rates would become final and no longer subject to refund. The remainder of the authorized revenue requirement that has yet to be collected would be amortized over a 12-month period.

Forward-Looking Rate Cases

The Utility routinely participates in forward-looking rate case applications before the CPUC and the FERC. Those applications include GRCs, where the revenue required for general operations ("base revenue") of the Utility is assessed and reset. In addition, the Utility is periodically involved in proceedings to adjust its regulated return on rate base.

Decisions in GRC proceedings are generally expected prior to the commencement of the period to which the rates would apply. However, delayed decisions in the Utility's GRCs may cause the Utility to develop its budgets based on possible outcomes, rather than authorized amounts. When decisions are delayed, the CPUC typically provides rate relief to the Utility effective as of the commencement of the rate case period (not effective as of the date of the delayed decision). Nonetheless, the Utility's spending during the period of the delay may exceed the authorized amount, without an ability for the Utility to seek cost recovery of such excess. If the Utility's spending during the period of the delay is less than the authorized amount, the Utility could be exposed to operational and financial risk associated with the lower level of work achieved compared to that funded by the CPUC.

Except as otherwise noted, the Utility is unable to predict the timing and outcome of the following applications. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected depending on the outcomes of these applications.

The Utility's rate cases that are pending, have pending appeals, or were completed in 2021 are summarized in the following table:

Rate Case	Request	Status
2023 GRC	Revenue requirement of $15.28 billion for 2023	Filed June 2021. A decision on the initial track of the proceeding is expected in the second quarter of 2023.
2019 GT&S	Removal of $39.4 million of disallowance	Approved January 2022.
2022 Cost of Capital	Leave cost of capital components at pre-2022 levels for 2022	Filed August 2021. Briefing is expected to be completed by March 2022.
2015 GT&S	Revenue requirement of $416 million	Settlement agreement to recover $356 million of revenue requirement filed July 2021.

2023 General Rate Case

On June 30, 2021, the Utility filed its 2023 GRC application with the CPUC. The 2023 GRC combined what had historically been separated into the GRC and GT&S rate cases. In the 2023 GRC, the CPUC will determine the annual amount of base revenues that the Utility will be authorized to collect from customers from 2023 through 2026 to recover its anticipated costs for gas distribution, gas transmission and storage, electric distribution, and electric generation and to provide the Utility an opportunity to earn its authorized rate of return. The Utility's revenue requirements for other portions of its operations, such as electric transmission, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.

In a GRC, the CPUC approves annual revenue requirements for the first year (a "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). For its 2023 test year, the Utility has requested revenue requirements of $15.46 billion, an increase of $3.56 billion over the adopted 2020 GRC and 2019 GT&S revenue requirements for 2022 of $11.90 billion. The GRC application further states that the Utility's requested 2023 revenue requirements represent a 9.6% increase over its total revenue requirements for 2022 (including both amounts that are authorized and that are requested outside of the GRC and remain subject to the regulatory process). The requested weighted-average GRC rate base for 2023 is approximately $48.52 billion, which corresponds to an increase of $9.35 billion over the authorized rate base for 2022 of $39.17 billion. The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized GRC revenues in 2024, 2025, and 2026 by $930 million, $590 million, and $381 million, respectively. The Utility estimated its proposed revenue requirements for 2024, 2025, and 2026 would result in revenue requirement increases of 2.4%, 1.9%, and 1.5%, compared to its total estimated revenue requirements for 2023, 2024, and 2025, respectively. Over the 2023-2026 GRC period, the Utility plans to make average annual capital investments of approximately $7.75 billion in gas distribution, transmission and storage, electric distribution, and electric generation infrastructure, and to improve safety, reliability, and customer service.

The following table compares the Utility's initial requested revenue requirements for 2023 with the comparable revenue requirements currently authorized for 2022, by both line of business and cost category:

Line of Business (1) (in millions)	**Amounts requested in the 2023 GRC application**	**Amounts currently authorized for 2022** (2)	**Requested increase compared to currently authorized amounts**
Gas distribution	$ 2,870	$ 2,321	$ 550
Gas transmission and storage	1,989	1,662	327
Electric distribution	8,171	5,514	2,657
Electric generation	2,431	2,404	26
Total revenue requirements	**$ 15,461**	**$ 11,901**	**$ 3,560**

(1) May not sum due to rounding.

(2) These amounts include revenues from Decision ("D.") 20-12-005 (the Utility's 2020 GRC), D.19-09-025 (the Utility's 2019 GT&S) adjusted for D.19-12-056 and Advice Letter ("AL") 4275-G/5887-E (Cost of Capital changes adopted for Long Term Debt and Common Stock) and AL 4367-G/6062-E (Excess Accumulated Deferred Income Taxes Pursuant to the 2017 Tax Act). Also included are the 2022 adopted revenue requirements associated with the following previously separately-funded projects: AL 5322-E (Energy Storage), D.16-12-065 (Electric Vehicle Charging Network Phase I), D.14-03-021 (Mobile Home Park to the Meter), D.20-11-035 (2019 CEMA), AL 4392-G/6100-E (WMBA and VMBA), AL 4444-G/6210-E (RTBA).

In the 2023 GRC application, the Utility proposed a series of safety, resiliency, and clean energy investments to further reduce wildfire risk and deliver safe, reliable, and clean energy service. Among other things, the Utility proposed to invest a total of approximately $31 billion between 2023 and 2026 to reduce wildfire risk; improve gas and electric system safety, reliability, and resiliency; increase the use of new, innovative technologies; and expand its clean energy infrastructure.

In addition to coverage that may be available from the private insurance market, the Utility also proposed to use self-insurance as part of its wildfire insurance program as follows: (1) the Utility's recommended approach, a new self-insurance structure whereby the Utility would seek customer-funded self-insurance in the amount of $250 million annually and traditional private insurance procurement for amounts between the accumulated self-insurance balance and $1.0 billion; or, alternatively (2) continuing the currently authorized mechanism whereby the Utility seeks procurement of wildfire liability insurance instruments through the private insurance market and is authorized to use any unspent authorized revenue requirements on self-insurance.

In addition, the Utility requested authorization to establish one new balancing account and one new memorandum account as follows:

- Catastrophic Events Straight-Time Labor Balancing Account, a two-way account which would recover straight-time labor costs associated with catastrophic events. These costs are currently recovered through the Catastrophic Events Memorandum Account process.

- Helms Capacity Memorandum Account, which would allow the Utility to track and recover the actual costs associated with upgrading the Helms Pumped Storage Facility through a future application.

The Utility did not seek recovery of compensation of PG&E Corporation's and the Utility's officers within the scope of 17 Code of Federal Regulations 240.3b-7.

On October 1, 2021, the CPUC issued a scoping memo indicating that the CPUC will issue a decision on an initial track of the proceeding in the second quarter of 2023. The scoping memo also established a second track of the 2023 GRC to consider costs incurred from 2019 to 2021 that are recorded in balancing or memorandum accounts for, among other work, wildfire mitigation and gas system safety improvements. The second track will review more than $500 million in capital and $160 million in expense included in the Utility's initial 2023 GRC application for the period from 2019 to 2020, plus additional costs recorded in memorandum and balancing accounts in 2021. The scoping memo indicated that the CPUC will issue a decision on the second track in the third quarter of 2023. The scoping memo also directed the Utility to file an update for its undergrounding program in February 2022.

On November 5, 2021, the Utility filed a motion to revise the proceeding schedule.

Between August 2021 and January 2022, the Utility served updates to its 2023 GRC testimony that would, if approved, reduce the requested revenue requirement in 2023 by approximately $181 million in the aggregate.

2020 General Rate Case

On December 3, 2020, the CPUC approved the final decision for the Utility's 2020 GRC.

Revenue Requirements and Attrition Year Revenues

The final decision approved a 2020 authorized revenue requirement of $9.102 billion, effective January 1, 2020. The CPUC also approved the revenue requirements for 2021 and 2022 as follows: an additional increase of $316 million in 2021 over the authorized 2020 revenue requirement, or a 3.5% increase, and an additional increase of $364 million in 2022, or a 3.9% increase. The Utility is authorized to collect in rates the difference between the revenue requirement in effect and the 2020 GRC decision-authorized revenue requirement for the period of January 1, 2020 to February 28, 2021 over the period of March 1, 2021 through December 31, 2022.

The final decision also allows the Utility to recover the annual cost of excess liability insurance for coverage of up to $1.4 billion. An advice letter is required for recovery of excess liability insurance costs for coverage exceeding $1.4 billion. The final decision also approved wildfire mitigation capital expenditures in the Community Wildfire Safety Program of $603 million in 2020, $931 million in 2021 and $1.15 billion in 2022. In addition, the final decision requires a reasonableness review and recovery of WMBA costs or unit costs for system hardening in excess of 115% of the adopted amounts and VMBA costs in excess of 120% of the adopted amounts through an application.

Rate Base and Capital Additions

The CPUC also adopted a rate base of $31.0 billion in 2021, or a 5.4% increase over 2020; and $33.0 billion in 2022, or a 6.3% increase over 2021. Consistent with AB 1054, the decision provides for a total of $2.83 billion in forecast capital spend without an equity return for the period of August 2019 to December 2022, which includes $931 million for 2021 and $1.15 billion for 2022.

Over the 2020-2022 GRC period, the decision provided average annual capital investments of approximately $4.5 billion in electric distribution, natural gas distribution and electric generation infrastructure.

2019 Gas Transmission and Storage Rate Case

As previously disclosed, on September 12, 2019, the CPUC approved the final decision in the 2019 GT&S rate case of the Utility. The CPUC adopted revenue requirements of $1.516 billion for 2021 and $1.580 billion for 2022, compared to the Utility's request of $1.693 billion for 2021 and $1.679 billion for 2022.

On October 23, 2019, the Utility filed an application with the CPUC requesting the rehearing of the final decision. Specifically, issues identified by the Utility include the adopted disallowance associated with vintage pipe replacement, reduction in the Utility's expense forecast for in-line inspections, and establishment of a memo account for Internal Corrosion Direct Assessment. On November 19, 2021, the CPUC issued a decision denying the Utility's application for rehearing but allowing the Utility to file an advice letter to remove the 2015 portion of the capital vintage pipe replacement disallowance. The advice letter was approved by the CPUC on January 21, 2022.

Removing the 2015 value of $39.4 million from the disallowance reduced the total disallowed amount from $237.3 million to $197.9 million.

Cost of Capital Proceedings

On December 19, 2019, the CPUC approved a final decision in the 2020 cost of capital application (the "2020 cost of capital application"), maintaining the Utility's return on common equity at the 2019 level of 10.25% for the three-year period beginning January 1, 2020. The decision maintained the common equity component of the Utility's capital structure at 52% and reduced its preferred stock component from 1% to 0.5%. The decision also approved the cost of debt requested by the Utility.

The Utility's annual cost of capital adjustment mechanism, which allows for changes in the Utility's authorized ROE and cost of debt, also remained unchanged by the final 2020 cost of capital application decision. The mechanism provides that in any year in which the difference between (i) the average Moody's utility bond rates (as measured in the 12-month period from October through September (the index)) and (ii) 4.5% (the benchmark) exceeds 100 basis points, the Utility's ROE will be adjusted by one-half of such difference, and the cost of debt will be trued up to the most recent recorded cost of debt. The Utility is to initiate this adjustment mechanism by filing an advice letter on or before October 15 of the year in which the mechanism triggered, to become effective on January 1 of the next year.

On August 23, 2021, the Utility filed an off-cycle 2022 cost of capital application with the CPUC based on the extraordinary event of the COVID-19 pandemic and related government response, which has decreased interest rates but has not reduced the cost of capital for electric utilities in general, and the Utility in particular, to the same extent as the overall financial markets (the "2022 cost of capital application"). The 2022 cost of capital application requested that the CPUC authorize the Utility's cost of capital for its electric generation, electric distribution, natural gas distribution, and natural gas transmission and storage rate base beginning on January 1, 2022 for 2022, 2023, and 2024. The Utility requested that the CPUC approve the Utility's proposed ratemaking capital structure (i.e., the relative weightings of common equity, preferred equity, and debt for ratemaking), ROE, cost of preferred stock, and cost of debt. The Utility proposed to establish a cost of long-term debt of 4.14%, a return on preferred stock of 5.52%, a ROE of 11%, and to retain the existing capital structure. The Utility also concurrently filed a motion requesting that the revenue requirement for the 2022 cost of capital be recorded in memorandum accounts to be trued-up following a final decision in this proceeding.

In September 2021, the cost of capital adjustment mechanism was triggered because the index was 117 basis points below the benchmark. As the 2022 cost of capital application was pending, the Utility did not file the October 15, 2021 advice letter to adjust rates. Subsequently, on October 28, 2021, the CPUC ruled that the 2022 cost of capital application did not suspend the adjustment mechanism as requested by the application. The ruling also required that the Utility comply with the cost of capital mechanism by filing the information that would have been included in the October 15, 2021 advice letter in the 2022 cost of capital application proceeding on November 8, 2021, which the Utility did.

On December 17, 2021, the CPUC issued a final decision authorizing the Utility's request to establish memorandum accounts to track revenue requirement changes starting on January 1, 2022 and leaving the cost of capital rates at current levels, subject to true-up based on the CPUC's decision on the 2022 cost of capital application.

On December 24, 2021, the CPUC issued a scoping memo in the 2022 cost of capital application limiting the scope of the Utility's 2022 cost of capital application to the 2022 cost of capital only. The scoping memo also affirmed that the Utility is to file a 2023 cost of capital application in April 2022 for the 2023 test year.

To set the 2022 cost of capital, the CPUC will consider (i) whether there are extraordinary circumstances that warrant a departure from the cost of capital mechanism for 2022; and (ii) if so, whether to leave the cost of capital components at pre-2022 levels for the year 2022, or open a second phase to consider alternative cost of capital proposals for the year 2022. The Utility's position is that there are extraordinary circumstances that warrant a departure from the cost of capital mechanism for 2022 and that the CPUC should leave the cost of capital components at pre-2022 levels for 2022.

If the CPUC determines that the 2022 cost of capital application establishes extraordinary circumstances that warrant a departure from the cost of capital mechanism for 2022 and leaves the Utility's cost of capital components at pre-2022 levels for 2022, the cost of long-term debt would be 4.17%, the return on preferred stock would be 5.52%, and the ROE would be 10.25%. If the CPUC opens a second phase of the proceeding, the CPUC would set the cost of capital for 2022 based on alternative cost of capital proposals that would address the technical cost of capital material included within the Utility's 2022 cost of capital application.

If the CPUC determines that there are not extraordinary circumstances that warrant a departure from the cost of capital mechanism for 2022, the cost of capital adjustment mechanism would operate and the cost of long-term debt would be 4.15%, the return on preferred stock would be 5.52%, and the ROE would be 9.67%. The resulting decrease in the CPUC jurisdictional gas and electric revenue requirement would be approximately $163 million ($99 million electric and $64 million gas).

The scoping memo called for briefing to be completed by March 25, 2022 but did not indicate timing for a PD or final decision.

2015 Gas Transmission and Storage Rate Case

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 2011 to 2014 capital spending 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 an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. For more information regarding this proceeding, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Transmission Owner Rate Cases

Transmission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases, respectively)

As previously disclosed, on January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of the FERC's decisions in the TO16 and TO17 rate cases that had granted the Utility a 50-basis point ROE incentive adder for its continued participation in the CAISO. If the FERC concluded on remand that the Utility should no longer be authorized to receive the 50 basis point ROE incentive adder, the Utility would incur a refund obligation of $1 million and $8.5 million for TO16 and TO17, respectively. Those rate case decisions were remanded to the FERC for further proceedings consistent with the Ninth Circuit Court of Appeals' opinion.

On July 18, 2019, the FERC issued its order on remand reaffirming its prior grant of the Utility's request for the 50-basis point ROE adder.

On March 17, 2020, the FERC issued its order denying requests for rehearing that were previously filed by several parties. On May 11, 2020, the CPUC and a number of other parties filed a petition for review of the FERC's orders in the Ninth Circuit Court of Appeals. Oral argument was held on April 16, 2021.

Transmission Owner Rate Case for 2017 (the "TO18" rate case)

As previously disclosed, on July 29, 2016, the Utility filed its TO18 rate case with the FERC requesting a 2017 retail electric transmission revenue requirement of $1.72 billion, a $387 million increase over the 2016 revenue requirement of $1.33 billion. The forecasted network transmission rate base for 2017 was $6.7 billion. The Utility sought a ROE of 10.9%, which included an incentive component of 50 basis points for the Utility's continuing participation in the CAISO.

On October 15, 2020, the FERC issued an order that, among other things, rejected 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. The order reopened the record for the limited purpose of allowing the participants to the proceeding an opportunity to present written evidence concerning the FERC's revised ROE methodology adopted in FERC Opinion No. 569-A, issued on May 21, 2020. Initial briefs and testimony were filed on December 14, 2020 and responses were filed on February 12, 2021.

On December 17, 2020 and June 17, 2021, the FERC issued orders denying requests for rehearing submitted by the Utility and intervenors. In 2021, the Utility filed four appeals. The appeals related to two issues: (1) impact of the Tax Act on TO18 rates in January and February 2018 and (2) aspects of the rehearing order other than the Tax Act. The appeals have been consolidated and are currently being held in abeyance until the FERC addresses the ROE issue.

As a result of an order denying rehearing on the common plant allocation, the Utility increased its Regulatory liabilities for amounts previously collected during the TO18, TO19, and TO20 rate case periods from 2017 through the fourth quarter of 2021 by approximately $324 million. A portion of these common plant costs are expected to be recovered at the CPUC in a separate application and as a result, as of December 31, 2021, the Utility has recorded approximately $197 million to Regulatory assets.

Aside from the ultimate outcome of the common plant allocation, which is subject to further appellate briefing and a further FERC decision on ROE, that order is not expected to result in a material impact on the Utility's financial condition, results of operations, liquidity, and cash flows. Some of the issues that will be decided in a final and unappealable TO18 decision, including the common plant allocation, will also be incorporated into the Utility's TO19 and TO20 rate cases. See "Transmission Owner Rate Case Revenue Subject to Refund" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Transmission Owner Rate Case for 2018 (the "TO19" rate case)

As previously disclosed, on July 27, 2017, the Utility filed its TO19 rate case with the FERC. On December 20, 2018, the FERC issued an order approving an all-party settlement filed by the Utility. 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 the issuance of a final, non-appealable TO18 decision. Additionally, if the Ninth Circuit Court of Appeals were to determine that the Utility was not entitled to the 50 basis point incentive adder for the Utility's continued CAISO participation, then the Utility would be obligated to make a refund to customers of approximately $25 million. See "Transmission Owner Rate Cases for 2015 and 2016" above for a discussion of the incentive adder. On December 20, 2018, the FERC issued an order approving the all-party settlement.

Transmission Owner Rate Case for 2019 (the "TO20" rate case)

As previously disclosed, on October 1, 2018, the Utility filed its TO20 rate case with the FERC requesting approval of a formula rate for the costs associated with the Utility's electric transmission facilities. On November 30, 2018, the FERC issued an order accepting the Utility's October 2018 filing, subject to hearings and refund, and established May 1, 2019 as the effective date for rate changes. The FERC also ordered that the hearings be held in abeyance pending settlement discussions among the parties.

On March 31, 2020, the Utility filed a partial settlement with the FERC, which the FERC approved on August 17, 2020. On October 15, 2020, the Utility filed a settlement with the FERC resolving all of the remaining issues in the formula rate proceedings, including the Utility's ROE, capital structure, depreciation rates, as well as certain other aspects of the Utility's formula rate. Specifically, the settlement establishes an all-in ROE of 10.45%; a fixed capital structure of 49.75% common stock, 49.75% debt, and 0.5% preferred stock; and fixed depreciation rates for various categories of transmission facilities (represented by individual FERC accounts). The term of the settlement continues until December 31, 2023 and the Utility will be required to file a replacement rate filing to be effective on January 1, 2024.

On December 30, 2020, the FERC approved the settlement without modifications.

Some of the issues that will be decided in a final and unappealable TO18 decision, including the common plant allocation, will also be incorporated into the Utility's TO19 and TO20 rate cases.

Other Regulatory Proceedings

Application to Sell General Office Complex

On September 30, 2020, the Utility filed an application with the CPUC to sell the SFGO located at 25 Beale Street, 45 Beale Street, 77 Beale Street, 50 Main Street, 215 Market Street and 245 Market Street in downtown San Francisco, and to recover costs to relocate its staff at the SFGO to a new headquarters at the Lakeside Building, and for appropriate ratemaking treatment of those transactions.

On May 21, 2021, the Utility entered into a purchase agreement with HNG Atlas US LP, to sell the SFGO for $800 million.

On May 26, 2021, the Utility filed an amended settlement agreement with the CPUC. Under the amended settlement, the parties agreed that (1) the Utility's headquarters strategy, including the move to the Lakeside Building, the sale of the SFGO, and the terms of the agreement to lease and the option to purchase the Lakeside Building, is reasonable, (2) all of the net gain on sale of the SFGO will be distributed to customers over five years, beginning in 2022, and (3) the costs associated with the Utility's move to the Lakeside Building and development will be considered at later stages of the proceeding through a petition for modification of the final decision in the proceeding.

The CPUC issued a final decision approving the purchase agreement and the ratemaking treatment proposed under the parties' settlement on August 19, 2021, and the sale closed on September 17, 2021. The final decision defers, until the petition for modification, determinations as to the amount of the Utility's cost recovery in connection with the anticipated purchase of the Lakeside Building and operating and capital expenses related to the transition to the Lakeside Building.

Application for Post-Emergence Securitization Transaction

On April 30, 2020, the Utility filed an application with the CPUC seeking authorization for a post-emergence transaction to recover $7.5 billion of 2017 wildfire claims costs through securitization that is designed to be rate neutral to customers, with the proceeds used to pay or reimburse the Utility for the payment of wildfire claims costs associated with 2017 Northern California wildfires. Among other uses, as a result of the proposed transaction, the Utility would retire $6.0 billion of Utility debt. Specifically, the application requested administration of the stress test methodology approved in the CHT OIR and a determination that $7.5 billion in 2017 catastrophic wildfire costs and expenses are stress test costs and eligible for securitization. In this context, a securitization refers to a financing transaction where a special purpose financing vehicle issues new debt that is secured by the proceeds of a new recovery charge to Utility customers. The application also proposed a customer credit designed to equal the bond charges over the life of the bonds, which would insulate customers from the charge on customer bills associated with the bonds.

On April 23, 2021, the CPUC issued a decision finding that $7.5 billion of the Utility's 2017 catastrophic wildfire costs and expenses are stress test costs that may be financed through the issuance of recovery bonds pursuant to Public Utilities Code sections 850 *et seq.* and approving a structure for the transaction. As requested, the decision authorizes the Utility to establish a customer credit trust funded by PG&E Corporation's shareholders, that will provide a monthly credit to customers that is anticipated to equal the securitized charges such that the securitization is designed to be rate neutral to customers. Subject to retention of the CPUC's existing jurisdiction, the decision adopts a transaction structure comprised of four elements (1) an initial shareholder contribution of $2.0 billion, with $1.0 billion to be contributed in 2022 and $1.0 billion to be contributed in 2024; (2) up to $7.59 billion of additional contributions funded by certain shareholder tax benefits; (3) a single CPUC review of the balance of the customer credit trust in 2040, with a single contingent supplemental shareholder contribution, if needed, up to $775 million in 2040; and (4) sharing with customers 25% of any surplus of shareholder assets in the customer credit trust at the end of the life of the trust. Three parties filed applications for rehearing of the decision on May 3, 2021, and the Utility filed a response to those applications on May 14, 2021. On August 12, 2021, the CPUC issued a decision denying the applications for rehearing.

Separately, on January 6, 2021, the Utility filed an additional application requesting that the CPUC issue a financing order authorizing the issuance of one or more series of recovery bonds in connection with the post-emergence transaction to finance, using securitization, the $7.5 billion of claims associated with the 2017 Northern California wildfires. On May 11, 2021, the CPUC issued a decision granting the Utility's January 2021 application for a financing order authorizing the issuance of $7.5 billion of recovery bonds in connection with the rate neutral securitization proceeding. Two parties filed applications for rehearing of the financing order, and the Utility filed a response to those applications for rehearing on June 4, 2021. On August 12, 2021, the CPUC issued a decision denying the applications for rehearing.

On September 10, 2021, TURN filed a petition for writ of review of the decision and financing order in state court. Responses to the petition were filed on October 15, 2021. TURN filed a reply in support of the petition on November 9, 2021.

Application for AB 1054 Securitization Transaction

AB 1054 provides that the first $5.0 billion expended in the aggregate by California's three large electric IOUs 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 has been allocated among the large electric IOUs in accordance with their Wildfire Fund allocation metrics. The Utility's allocation is $3.21 billion. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) AB 1054 contemplates that such capital expenditures may be financed using a structure that securitizes a dedicated customer charge.

On February 24, 2021 the Utility filed an application with the CPUC seeking authorization for a transaction to finance, using securitization, up to $1.19 billion of fire risk mitigation capital expenditures that were or will be incurred by the Utility in 2020 and 2021, with the final amount to be financed based on recorded 2020 and 2021 Community Wildfire Safety Program capital expenditures incurred by the Utility prior to the securitization transaction.

The application requested that the CPUC issue a financing order authorizing one or more series of recovery bonds, determine that the issuance of the bonds and collection through fixed recovery charges is just and reasonable, consistent with the public interest and would reduce rates on a present value basis compared to traditional utility financing mechanisms, and authorize the Utility to collect a non-bypassable charge sufficient to pay debt service on the recovery bonds. The application also requested to exclude the securitized debt from the Utility's ratemaking capital structure and to adjust its 2020 GRC revenue requirement following the issuance of the recovery bonds.

On June 24, 2021, the CPUC issued a decision granting the Utility's application and authorizing the Utility to issue up to approximately $1.2 billion of recovery bonds. On July 6, 2021, the financing order became final and non-appealable. On November 12, 2021, PG&E Recovery Funding LLC issued approximately $860 million of senior secured recovery bonds. The recovery bonds were issued in three tranches: (1) approximately $266 million with an interest rate of 1.46% and is due July 15, 2033, (2) approximately $160 million with an interest rate of 2.28% and is due January 15, 2038, and (3) approximately $434 million with an interest rate of 2.82% and is due July 15, 2048.

2020-2022 Wildfire Mitigation Plan

As previously disclosed, on February 7, 2020, the Utility submitted its 2020 WMP and the related utility survey. The Utility's 2020 WMP describes the Utility's wildfire safety programs, which are focused on three key areas: reducing the potential for fires to be started by electrical equipment, reducing the potential for fires to spread, and minimizing the frequency, scope and duration of PSPS events, as well as providing historical data. The Utility's 2020 WMP covers a three-year period from 2020 to 2022 but is updated annually.

The Utility's 2021 WMP was submitted on February 5, 2021. The 2021 WMP updated the 2020 WMP and addressed the Utility's wildfire safety programs focused on reducing the potential for catastrophic wildfires related to electrical equipment, reducing the potential for fires to spread and reducing the impact of PSPS events.

On September 22, 2021, OEIS issued a final action statement approving the Utility's 2021 WMP and on October 21, 2021, the CPUC ratified OEIS's approval.

In 2021, the Utility notified the CPUC that it had missed inspections and other targets subject to the 2020 WMP. The Utility is undertaking a review of its electric asset inspections. For more information, see "Electric Asset Inspections" below.

On December 16, 2021, the CPUC closed the WMP proceeding, noting that OEIS is now responsible for review and approval of the WMP.

OII to Examine the Late 2019 Public Safety Power Shutoff Events

On November 13, 2019, the CPUC issued an OII to determine "whether California's IOUs prioritized safety and complied with the CPUC's regulations and requirements with respect to their PSPS events in late 2019."

On June 7, 2021, the CPUC issued a final decision in the case that found each of the large electric IOUs to be noncompliant with CPUC-required guidelines in certain of their 2019 PSPS events. The decision included a financial remedy and a number of corrective actions. The financial remedy consists of forgoing collection of revenues from customers associated with electricity not sold during future PSPS events until it can be demonstrated that the utilities have made improvements in assessing public harm when determining whether to initiate a PSPS event. The corrective actions involve the Utility's processes, reporting, and other aspects of its PSPS program. On July 7, 2021, the Acton Town Council filed an application to rehear the decision. Responses to the application for rehearing were filed on July 22, 2021.

Integrated Resource Planning Procurement

On November 13, 2019, the CPUC issued a decision that takes a number of steps to address the potential for system RA shortages beginning in 2021. The decision requires incremental procurement of system-level qualifying RA capacity of 3,300 MWs by all LSEs operating within the CAISO's balancing area for the period 2021-2023, of which the Utility is responsible for 716.9 MWs for its bundled customer portion. The decision requires that at least 50% of LSE resource responsibilities come online by August 1, 2021, at least 75% by August 1, 2022, and the remaining by August 1, 2023. Additionally, the decision directs the IOUs to act as the backstop procurement agent for CCAs and energy service providers that choose not to voluntarily self-procure or that fail to meet their procurement responsibilities after electing to self-provide their assigned MWs of system RA capacity under the decision.

The Utility procured its required RA capacity for the August 1, 2021 milestone from third parties through CPUC-approved contracts for lithium-ion battery energy storage resources with terms ranging from 10-15 years. On December 22, 2020, the Utility filed an advice letter seeking CPUC approval of an additional group of similar contracts that would satisfy the balance of the Utility's procurement obligations for the August 1, 2022 and August 1, 2023 milestones. On April 15, 2021, the CPUC approved the contracts.

On June 24, 2021, the CPUC adopted a mid-term reliability decision to address incremental electric system reliability needs between 2024 and 2026 due to, in part, the pending retirements of Diablo Canyon and once-through-cooling natural gas plants in Southern California by requiring at least 11,500 MW of additional net qualifying capacity to be procured by LSEs subject to the CPUC's integrated resource planning authority. The decision sets procurement requirements of 2,000 MW by 2023, an additional 6,000 MW by 2024, an additional 1,500 MW by 2025, and an additional 2,000 MW by 2026. The decision sets the Utility's share of the procurement at 2,302 MW of incremental net qualifying capacity.

On January 21, 2022, the Utility filed an advice letter with the CPUC seeking approval of a group of nine long-term RA agreements to meet a portion of its procurement requirements under the CPUC's mid-term reliability decision. The agreements are each for a term of 15 years and collectively supply 1,598.7 MW of lithium-ion energy storage capacity with some projects expected to be operational in 2023 and others in 2024.

OIR to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities

On July 20, 2020, the CPUC initiated a rulemaking proceeding to consider ways to strengthen the risk-based decision-making framework that energy utilities use to assess, manage, mitigate and minimize safety risks.

On November 4, 2021, the CPUC issued a final decision adopting 32 safety and operational metrics, which can serve as triggering events in the EOEP and requiring the Utility to report on performance against these metrics on a semi-annual basis. The Utility is required to submit the first report by March 31, 2022. The Utility will propose one- and five-year targets for each metric in such report.

OIR to Revisit Net Energy Metering Tariffs

On August 17, 2020, the CPUC initiated a rulemaking proceeding to develop a successor to the existing NEM tariffs. The successor tariff is being developed pursuant to the requirements of AB 327. Under AB 327, the successor to the existing NEM tariffs should provide customer-generators with credit or compensation for electricity generated by their renewable facilities based on the value of that generation to all customers and allow customer-sited renewable generation to grow sustainably among different types of customers.

On December 13, 2021, the CPUC issued a PD that would reduce the compensation for new non-CARE NEM customers by about 80 percent for standalone solar and about 60 percent for solar-paired storage. Commercial customer NEM compensation would be reduced by about 35 percent. Additionally, the PD would reduce the legacy period for existing non-CARE NEM customers from 20 years to 15 years after which such customers would transition to the successor tariff. Comments and reply comments on the PD were filed in January 2022. The PD has not yet been scheduled to be voted on by the CPUC.

OIR to Address Energy Utility Customer Debt Accumulated during the COVID-19 Pandemic

On February 11, 2021, the CPUC initiated a rulemaking proceeding to consider arrearage relief for utility customers with outstanding utility bills when the moratorium on service disconnections ended. The OIR will evaluate a more global program beyond the currently approved arrearage management program focused on low-income residential customers that is funded by the Utility's customers. The OIR may consider various funding approaches for this expanded debt forgiveness proposal, which could include shareholder funding.

On June 30, 2021, the CPUC issued a final decision directing the Utility and other IOUs to automatically enroll residential customers and small business customers more than 60 days in arrears in payment plans. The decision also extended the moratorium on service disconnections for residential and small business, as well as medium and large commercial and industrial customers, through September 30, 2021.

On November 19, 2021, the CPUC issued a decision authorizing IOUs to allocate payments made on past-due electric utility bills proportionally between utilities and CCAs through September 2024.

Self-Reports to the CPUC

The Utility self-reports certain errors and omissions to the CPUC. The Utility could face penalties, enforcement actions, or other adverse legal or regulatory consequences for these errors or omissions, including under the EOEP. The Utility is unable to predict the likelihood and the amount of potential fines or penalties, if any, related to these matters.

Electric Asset Inspections

The Utility has notified the CPUC of various errors relating to inspections and maintenance of its electric assets or implementation of WMP initiatives. These notices include missed inspections or the inability to locate records evidencing performance of inspections required under CPUC GOs 95 and 165 (including failure to perform inspections in compliance with GO 165 of approximately 55,000 poles in 2020) and errors regarding reporting meeting targets set by the Utility's 2020 WMP. In these notices, the Utility describes the failures and corrective actions the Utility is taking to remediate these issues and to prevent recurrence in the future. Among other corrective measures, the Utility has developed short-term and longer-term systemic corrective actions to address these errors, including performing enhanced inspections for poles with outdated or incomplete GO 165 inspection records and strengthening the Utility's asset registry, as well as corrective actions regarding reporting on the progress toward WMP targets.

The Utility continues to evaluate whether there are additional failures to comply with GOs 95 and 165 and the 2020 WMP, beyond those identified in submitted self-reports. The Utility intends to update the CPUC upon completion of its reviews.

On November 21, 2021, the SED issued two citations to the Utility in relation to the Utility's self-reports. One citation was for incomplete inspections performed on distribution poles as required under GO 165, and the other citation was for the Utility's failure to adequately inspect a transmission line. The citations resulted in penalties of $2.5 million and $5 million, respectively, which the Utility paid in full on December 22, 2021.

Subsurface Electric Ducts

On October 21, 2021, the Utility notified the CPUC of inconsistent application of the requirements to locate and mark empty subsurface electric ducts in accordance with Government Code section 4216(k), 4216(s) and 4216.3(a)(1)(A).

LEGISLATIVE AND REGULATORY INITIATIVES

Assembly Bill 242

Assembly Bill 242, which was signed into law on September 23, 2021, expanded the definition of a "covered wildfire" from AB 1054 to also include those wildfires determined by a court of competent jurisdiction to be caused by an electrical corporation, and those wildfires asserted to have been caused by an electrical corporation that result in a court-approved dismissal resulting from the settlement of third-party damage claims.

Assembly Bill 135

On July 16, 2021, the California governor approved AB 135, which established the CAPP. CAPP enables the IOUs to apply for a statewide total of approximately $695 million to offset customer arrearages incurred during the COVID-19 pandemic. The Utility received approximately $300 million in January 2022 to reduce the amounts owed by customer accounts in arrears. The amount of funding was determined by the California Department of Community Services and Development, which is the agency responsible for administering the CAPP.

Vaccine Mandates

On September 9, 2021, President Biden issued an EO that would require certain COVID-19 precautions for government contractors and their subcontractors, including mandatory employee vaccination. The requirements under the EO is currently stayed pending the outcome of ongoing litigation. The ultimate implementation of the EO could result in workplace disruptions, employee attrition, and difficulty securing future labor needs.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. See Item 1A. Risk Factors, "Environmental Regulation" in Item 1. and "Environmental Remediation Contingencies" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and the Utility are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit. The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes.

Commodity Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices do not affect earnings. Such fluctuations, however, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs in its GRC through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $5 million and $14 million at December 31, 2021 and 2020, respectively. See Note 10 of the Notes to the Consolidated Financial Statements in Item 8. for further discussion of price risk management activities.

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2021 and 2020, if interest rates changed by one percent for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the pre-tax impact on net income over the next 12 months would be $76 million and $89 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. See Note 5 of the Notes to the Consolidated Financial Statements in Item 8. for further discussion of interest rates.

Energy Procurement Credit Risk

The Utility conducts business with counterparties mainly in the energy industry to purchase electricity or gas and related services, including the CAISO market, other California IOUs, municipal utilities, energy trading companies, pipelines, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas and related services, then the Utility may find it necessary to procure electricity or gas at current market prices or seek alternate services, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security. Security may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Security or performance assurance may be required from the Utility or counterparties when current net receivables/payables and exposure exceed contractually specified limits.

The following table summarizes the Utility's energy procurement credit risk exposure to its counterparties:

	Exposure [1] (in millions)		Number of Wholesale Customers or Counterparties >10%	Net Credit Exposure to Wholesale Customers or Counterparties >10% (in millions)	
December 31, 2021	$	570	1	$	63
December 31, 2020	$	250	2	$	57

[1] Exposure is the positive exposure maximum that equals mark-to-market value on physically and financially settled contracts, plus net receivables (payables) where netting is contractually allowed minus collateral posted by counterparties and held by the Utility plus collateral posted by the Utility and held by the counterparties. For purposes of this table, parental guarantees are not included as part of the calculation. Exposure amounts reported above do not include adjustments for time value or liquidity.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting estimates due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates and assumptions. These accounting estimates and their key characteristics are outlined below.

Contributions to the Wildfire Fund

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 customers, (ii) $7.5 billion in initial contributions from California's three large electric IOUs, and (iii) $300 million in annual contributions paid by California's three large electric IOUs for a 10-year period. The contributions from the IOUs will be effectively borne by their respective shareholders, as they will not be permitted to recover these costs through rates. The costs of the initial and annual contributions are allocated among the IOUs pursuant to a "Wildfire Fund allocation metric" set forth in AB 1054 based on land area in the applicable IOU's service territory classified as HFTDs 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).

On the Emergence 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. The other large electric IOUs made their initial contributions to the Wildfire Fund in September 2019. On December 30, 2020 and 2021, the Utility made its second and third annual contributions of $193 million each to the Wildfire Fund. As of December 31, 2021, PG&E Corporation and the Utility have seven remaining annual contributions of $193 million (based on the current Wildfire Fund allocation metric). 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.

As of December 31, 2021, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $1.1 billion in Other non-current liabilities, $461 million in current assets - Wildfire fund asset, and $5.3 billion in non-current assets - Wildfire fund asset in the Consolidated Balance Sheets. During the years ended December 31, 2021 and 2020, the Utility recorded amortization and accretion expense of $517 million and $413 million, respectively. The amortization of the asset, accretion of the liability, and acceleration of the amortization of the asset is reflected in Wildfire Fund expense in the Consolidated Statements of Income. Expected contributions recorded in Wildfire Fund asset on the Consolidated Balance Sheets are discounted to the present value using the 10-year U.S. 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 creates annual distributions of potential losses due to fires that could be attributed to the participating electric utilities. Starting with a five-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 six years. As of December 31, 2021, a 10% change to the assumption around current and future mitigation effort effectiveness would increase the amortization period by three years assuming greater effectiveness and would decrease the amortization period by two 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 and determination of any amounts required to be reimbursed to the Wildfire Fund, 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 and 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 assess the Wildfire Fund asset for acceleration of the amortization of the asset 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 acceleration of the amortization of the asset 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' services territories since July 12, 2019, including fires for which the cause is currently unknown, which may in the future be determined to be covered by the Wildfire Fund. As of December 31, 2021, PG&E Corporation and the Utility recorded $150 million in Other noncurrent assets for Wildfire Fund receivables related to the 2021 Dixie fire and $43 million of accelerated amortization, reflected in Wildfire Fund expense.

For more information, see "Initial and Annual Contributions to the Wildfire Fund Established Pursuant to AB 1054" in Note 3 and "Wildfire Fund under AB 1054" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Loss Contingencies

As discussed below, PG&E Corporation and the Utility have recorded material accruals for various wildfire-related, enforcement and legal matters, and environmental remediation liabilities. PG&E Corporation and the Utility have also recorded insurance receivables for third-party claims.

Wildfire-Related Liabilities

PG&E Corporation and the Utility are subject to potential liabilities related to wildfires. PG&E Corporation and the Utility record a wildfire-related liability when they determine that a loss is probable and they can reasonably estimate the loss or a range of losses. The provision is based on the lower end of the range, unless an amount within the range is a better estimate than any other amount.

Potential liabilities related to wildfires depend on various factors, including negotiations and settlements or the cause of each fire, contributing causes of the fires (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 extent to which future claims arise, 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 or fines that may be imposed by governmental entities. 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 or the Utility. For example, the Utility's wildfire-related accruals have changed in the past as new facts and information became available to the Utility, including the availability of new evidence and additional information about the scope and nature of damages.

The process for estimating wildfire-related liabilities 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. See Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Enforcement and Litigation Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency 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, 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. Actual results may differ materially from these estimates and assumptions. See Note 14 and "Enforcement and Litigation Matters" in Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Loss Recoveries

PG&E Corporation and the Utility have recovery mechanisms available for wildfire liabilities including from insurance, through rates, and from the Wildfire Fund. The Utility has liability insurance from various insurers, which provides coverage for third-party claims. PG&E Corporation and the Utility record a receivable for a recovery when it is deemed probable that recovery of a recorded loss will occur and they can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Loss recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with similar events, conversations with the Wildfire Fund administrators, the CPUC and FERC, and other information and events pertaining to a particular matter. See "Loss Recoveries" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Environmental Remediation Liabilities

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in the future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party. Such contingencies may exist for the remediation of hazardous substances at various potential sites, including former MGP sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action. (In some instances, the Utility may initiate action to determine its remediation liability for sites that it no longer owns in cooperation with regulatory agencies. For example, the Utility has a program related to certain former MGP sites.) Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonably estimate the loss or a range of possible losses. 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 is subjective and requires significant judgment. Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience for costs incurred at similar sites depending on the level of information available. Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of time directly to the remediation effort. These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of the remediation effort.

As of December 31, 2021 and 2020, the Utility's accruals for undiscounted gross environmental liabilities were $1.3 billion each. The Utility's undiscounted future costs could increase to as much as $2.2 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

Regulatory Accounting

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. Despite the ongoing losses related to wildfires (see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.), there is no actual or anticipated change in the cost of service regulation of the Utility's operations. Therefore, the Utility continues to apply the accounting ASC 980, *Regulated Operations*. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 3 as well as Note 4 of the Notes to the Consolidated Financial Statements in Item 8. As of December 31, 2021, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $12.7 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $13.8 billion.

Determining probability requires significant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. For some of the Utility's regulatory assets, including utility retained generation, the Utility has determined that the costs are recoverable based on specific approval from the CPUC. The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the regulatory assets for pension benefits; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. If the Utility determined that it is no longer probable that regulatory assets would be recovered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. If regulatory accounting did not apply, the Utility's future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

A portion of the Utility's regulatory asset balances relate to items which could not be anticipated by the Utility during CPUC GRC rate requests resulting from catastrophic events, changes in regulation, or extraordinary changes in operating practices. The Utility may seek authority to track incremental costs in a memorandum account and the CPUC may authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. These accounts, which include the CEMA, WEMA, FHPMA, FRMMA, WMPMA, VMBA, WMBA, and RTBA among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. In addition, the CPPMA and RUBA accounts track costs incurred to implement the CPUC's Emergency Authorization and Order Directing Utilities to Implement Emergency Customer Protections to Support California Customers During the COVID-19 Pandemic. While the Utility generally believes such costs are recoverable, rate recovery requires CPUC authorization in separate proceedings or through a GRC. For more information, see "Regulatory Matters - Application for Recovery of Costs Recorded in the Wildfire Expense Memorandum Account" and "Regulatory Matters - Catastrophic Event Memorandum Accounts and Applications" above.

Additionally, SB 901 provides a mechanism for the CPUC to potentially allow recovery in future rates, through a securitization mechanism, 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. The Utility must evaluate the likelihood of recovery in future rates each period. If the criteria are met at a later date, the Utility would recognize a regulatory asset and a related gain in the consolidated income statement in the period in which it is determined that the likelihood of recovery is probable.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

Asset Retirement Obligations

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. See Notes 3 and 4 of the Notes to the Consolidated Financial Statements in Item 8.

To estimate its liability, the Utility uses a discounted cash flow model based upon significant estimates and assumptions about future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2021, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was approximately $5.3 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets.

Pension and Other Postretirement Benefit Plans

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences between actuarial assumptions and actual plan results. These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery through rates. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability. See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses. See Note 12 of the Notes to the Consolidated Financial Statements in Item 8.

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2022 was 6.0%, 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 Utility's defined benefit pension plan, the assumed return of 5.5% 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 approximately 817 Aa-grade non-callable bonds at December 31, 2021. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (Decrease) in Assumption	Increase in 2021 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2021
Discount rate	(0.50)%	$ 111	$ 1,872
Rate of return on plan assets	(0.50)%	103	—
Rate of increase in compensation	0.50 %	51	403

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

(in millions)	Increase (Decrease) in Assumption	Increase in 2021 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2021
Health care cost trend rate	0.50 %	$ 9	$ 58
Discount rate	(0.50)%	12	138
Rate of return on plan assets	(0.50)%	15	—

NEW ACCOUNTING PRONOUNCEMENTS

See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in MD&A in Item 7 and in Note 10: Derivatives and Note 11: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(in millions, except per share amounts)

	Year ended December 31,		
	2021	**2020**	**2019**
Operating Revenues			
Electric	$ 15,131	$ 13,858	$ 12,740
Natural gas	5,511	4,611	4,389
Total operating revenues	**20,642**	**18,469**	**17,129**
Operating Expenses			
Cost of electricity	3,232	3,116	3,095
Cost of natural gas	1,149	782	734
Operating and maintenance	10,200	8,684	8,725
Wildfire-related claims, net of recoveries	258	251	11,435
Wildfire fund expense	517	413	—
Depreciation, amortization, and decommissioning	3,403	3,468	3,234
Total operating expenses	**18,759**	**16,714**	**27,223**
Operating Income (Loss)	1,883	1,755	(10,094)
Interest income	20	39	82
Interest expense	(1,601)	(1,260)	(934)
Other income, net	457	483	250
Reorganization items, net	(11)	(1,959)	(346)
Income (Loss) Before Income Taxes	**748**	**(942)**	**(11,042)**
Income tax provision (benefit)	836	362	(3,400)
Net Loss	**(88)**	**(1,304)**	**(7,642)**
Preferred stock dividend requirement of subsidiary	14	14	14
Loss Attributable to Common Shareholders	**$ (102)**	**$ (1,318)**	**$ (7,656)**
Weighted Average Common Shares Outstanding, Basic	**1,985**	**1,257**	**528**
Weighted Average Common Shares Outstanding, Diluted	**1,985**	**1,257**	**528**
Net Loss Per Common Share, Basic	**$ (0.05)**	**$ (1.05)**	**$ (14.50)**
Net Loss Per Common Share, Diluted	**$ (0.05)**	**$ (1.05)**	**$ (14.50)**

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year ended December 31,		
	2021	**2020**	**2019**
Net Loss	**$ (88)**	**$ (1,304)**	**$ (7,642)**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $3, $7, and $0, at respective dates)	7	(17)	(1)
Total other comprehensive income (loss)	**7**	**(17)**	**(1)**
Comprehensive Loss	**(81)**	**(1,321)**	**(7,643)**
Preferred stock dividend requirement of subsidiary	**14**	**14**	**14**
Comprehensive Loss Attributable to Common Shareholders	**$ (95)**	**$ (1,335)**	**$ (7,657)**

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2021	**2020**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 291	$ 484
Restricted Cash	16	143
Accounts receivable		
Customers (net of allowance for doubtful accounts of $171 million and $146 million at respective dates) (includes $2.06 billion and $1.63 billion related to VIEs, net of allowance for doubtful accounts of $171 million and $143 million at respective dates)	2,345	1,883
Accrued unbilled revenue (includes $1.09 billion and $959 million related to VIEs at respective dates)	1,207	1,083
Regulatory balancing accounts	2,999	2,001
Other	1,784	1,172
Regulatory assets	496	410
Inventories		
Gas stored underground and fuel oil	44	95
Materials and supplies	552	533
Wildfire fund asset	461	464
Other	882	1,334
Total current assets	**11,077**	**9,602**
Property, Plant, and Equipment		
Electric	69,482	66,982
Gas	25,979	24,135
Construction work in progress	3,479	2,757
Financing lease and other	20	20
Total property, plant, and equipment	**98,960**	**93,894**
Accumulated depreciation	(29,134)	(27,758)
Net property, plant, and equipment	**69,826**	**66,136**
Other Noncurrent Assets		
Regulatory assets	9,207	8,978
Nuclear decommissioning trusts	3,798	3,538
Operating lease right of use asset	1,234	1,741
Wildfire fund asset	5,313	5,816
Income taxes receivable	9	67
Other (includes net noncurrent accounts receivable of $187 million and $0 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $0 at respective dates)	2,863	1,978
Total other noncurrent assets	**22,424**	**22,118**
TOTAL ASSETS	**$ 103,327**	**$ 97,856**

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31,	
	2021	**2020**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,184	$ 3,547
Long-term debt, classified as current (includes $18 million and $0 related to VIEs at respective dates)	4,481	28
Accounts payable		
Trade creditors	2,855	2,402
Regulatory balancing accounts	1,121	1,245
Other	679	580
Operating lease liabilities	468	533
Disputed claims and customer refunds	—	242
Interest payable	481	498
Wildfire-related claims	2,722	2,250
Other	2,436	2,256
Total current liabilities	**17,427**	**13,581**
Noncurrent Liabilities		
Long-term debt (includes $1.82 billion and $1.0 billion related to VIEs at respective dates)	38,225	37,288
Regulatory liabilities	11,999	10,424
Pension and other postretirement benefits	860	2,444
Asset retirement obligations	5,298	6,412
Deferred income taxes	3,177	1,398
Operating lease liabilities	810	1,208
Other	4,308	3,848
Total noncurrent liabilities	**64,677**	**63,022**
Contingencies and Commitments (Notes 14 and 15)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 3,600,000,000 and 3,600,000,000 shares at respective dates; 1,985,400,540 and 1,984,678,673 shares outstanding at respective dates	35,129	30,224
Treasury Stock, at cost; 477,743,590 and 0 shares at respective dates	(4,854)	—
Reinvested earnings	(9,284)	(9,196)
Accumulated other comprehensive loss	(20)	(27)
Total shareholders' equity	**20,971**	**21,001**
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	**21,223**	**21,253**
TOTAL LIABILITIES AND EQUITY	**$ 103,327**	**$ 97,856**

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2021	**2020**	**2019**
Cash Flows from Operating Activities			
Net income (loss)	$ (88)	$ (1,304)	$ (7,642)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	3,403	3,468	3,234
Bad Debt Expense	154	150	46
Allowance for equity funds used during construction	(133)	(140)	(79)
Deferred income taxes and tax credits, net	1,783	1,097	(2,948)
Reorganization items, net (Note 2)	(73)	1,458	108
Wildfire fund expense	517	413	—
Disallowed capital expenditures	—	17	581
Other	248	249	161
Effect of changes in operating assets and liabilities:			
Accounts receivable	(589)	(1,182)	(104)
Wildfire-related insurance receivable	(723)	1,564	35
Inventories	(32)	6	(80)
Accounts payable	117	58	516
Wildfire-related claims	472	(16,525)	(114)
Income taxes receivable/payable	—	—	23
Other current assets and liabilities	244	(1,079)	77
Regulatory assets, liabilities, and balancing accounts, net	(2,266)	(2,451)	(1,417)
Liabilities subject to compromise	—	413	12,222
Contributions to Wildfire fund	(193)	(5,200)	—
Other noncurrent assets and liabilities	(579)	(142)	197
Net cash provided by (used in) operating activities	**2,262**	**(19,130)**	**4,816**
Cash Flows from Investing Activities			
Capital expenditures	(7,689)	(7,690)	(6,313)
Proceeds from sale of the SFGO	749	—	—
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,678	1,518	956
Purchases of nuclear decommissioning trust investments	(1,702)	(1,590)	(1,032)
Other	59	14	11
Net cash used in investing activities	**(6,905)**	**(7,748)**	**(6,378)**
Cash Flows from Financing Activities			
Proceeds from debtor-in-possession credit facility	—	500	1,850
Repayments of debtor-in-possession credit facility	—	(2,000)	(350)
Debtor-in-possession credit facility debt issuance costs	—	(6)	(113)
Bridge facility financing fees	—	(73)	—
Borrowings under credit facilities	9,730	8,554	—
Repayments under credit facilities	(9,976)	(3,949)	—
Credit facilities financing fees	(9)	(22)	—
Short-term debt financing, net of issuance costs of $1, $2, and $0 at respective dates	300	1,448	—

Short-term debt matured	(1,450)	—	—
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $43, $178, and $0 at respective dates	5,474	13,497	—
Repayment of long-term debt	(87)	(764)	—
Proceeds from sale of future revenue from transmission tower license sales, net of fees	370	—	—
Exchanged debt financing fees	—	(103)	—
Common stock issued	—	7,582	85
Equity Units issued	—	1,304	—
Other	(29)	(40)	(8)
Net cash provided by financing activities	**4,323**	**25,928**	**1,464**
Net change in cash, cash equivalents, and restricted cash	**(320)**	**(950)**	**(98)**
Cash, cash equivalents, and restricted cash at January 1	**627**	**1,577**	**1,675**
Cash, cash equivalents, and restricted cash at December 31	**$ 307**	**$ 627**	**$ 1,577**
Less: Restricted cash and restricted cash equivalents	(16)	(143)	(7)
Cash and cash equivalents at December 31	**$ 291**	**$ 484**	**$ 1,570**
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest, net of amounts capitalized	$ (1,404)	$ (1,563)	$ (10)
Income taxes, net	99	—	—
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$ 1,311	$ 515	$ 826
Operating lease liabilities arising from obtaining ROU assets	100	13	2,816
Common stock issued in satisfaction of liabilities	—	8,276	—
Increase to PG&E Corporation common stock and treasury stock in connection with the Share Exchange and Tax Matters Agreement	4,854	—	—

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(in millions, except share amounts)

	Common Stock		Treasury Stock						
	Shares	Amount	Shares	Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non-controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2018	**520,338,710**	**$ 12,910**	**—**	**$ —**	**$ (250)**	**$ (9)**	**$ 12,651**	**$ 252**	**$ 12,903**
Net loss	—	—	—	—	(7,642)	—	(7,642)	—	(7,642)
Other Comprehensive loss	—	—	—	—	—	(1)	(1)	—	(1)
Common stock issued, net	8,898,031	85	—	—	—	—	85	—	85
Stock-based compensation amortization	—	43	—	—	—	—	43	—	43
Balance at December 31, 2019	**529,236,741**	**$ 13,038**	**—**	**$ —**	**$ (7,892)**	**$ (10)**	**$ 5,136**	**$ 252**	**$ 5,388**
Net loss	—	—	—	—	(1,304)	—	(1,304)	—	(1,304)
Other comprehensive loss	—	—	—	—	—	(17)	(17)	—	(17)
Common stock issued, net	1,455,441,932	15,854	—	—	—	—	15,854	—	15,854
Equity units issued	—	1,304	—	—	—	—	1,304	—	1,304
Stock-based compensation amortization	—	28	—	—	—	—	28	—	28
Balance at December 31, 2020	**1,984,678,673**	**$ 30,224**	**—**	**$ —**	**$ (9,196)**	**$ (27)**	**$ 21,001**	**$ 252**	**$ 21,253**
Net loss	—	—	—	—	(88)	—	(88)	—	(88)
Other comprehensive income	—	—	—	—	—	7	7	—	7
Common stock issued, net [(1)]	721,867	4,854	—	—	—	—	4,854	—	4,854
Treasury stock acquired	—	—	477,743,590	(4,854)	—	—	(4,854)	—	(4,854)
Stock-based compensation amortization	—	51	—	—	—	—	51	—	51
Balance at December 31, 2021	**1,985,400,540**	**$ 35,129**	**477,743,590**	**$ (4,854)**	**$ (9,284)**	**$ (20)**	**$ 20,971**	**$ 252**	**$ 21,223**

[(1)] Excludes 477,743,590 shares of common stock issued to ShareCo. For more information, see Note 6 below.

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(in millions)

	Year ended December 31,		
	2021	**2020**	**2019**
Operating Revenues			
Electric	$ 15,131	$ 13,858	$ 12,740
Natural gas	5,511	4,611	4,389
Total operating revenues	**20,642**	**18,469**	**17,129**
Operating Expenses			
Cost of electricity	3,232	3,116	3,095
Cost of natural gas	1,149	782	734
Operating and maintenance	10,194	8,707	8,750
Wildfire-related claims, net of recoveries	258	251	11,435
Wildfire fund expense	517	413	—
Depreciation, amortization, and decommissioning	3,403	3,469	3,233
Total operating expenses	**18,753**	**16,738**	**27,247**
Operating Income (Loss)	1,889	1,731	(10,118)
Interest income	22	39	82
Interest expense	(1,373)	(1,111)	(912)
Other income, net	512	470	239
Reorganization items, net	(12)	(310)	(320)
Income (Loss) Before Income Taxes	**1,038**	**819**	**(11,029)**
Income tax provision (benefit)	900	408	(3,407)
Net Income (Loss)	**138**	**411**	**(7,622)**
Preferred stock dividend requirement	14	14	14
Income (Loss) Available for Common Stock	**$ 124**	**$ 397**	**$ (7,636)**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year ended December 31,		
	2021	2020	2019
Net Income (Loss)	**$ 138**	**$ 411**	**$ (7,622)**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $1, $2, and $1, at respective dates)	(4)	(6)	2
Total other comprehensive income (loss)	**(4)**	**(6)**	**2**
Comprehensive Income (Loss)	**$ 134**	**$ 405**	**$ (7,620)**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2021	Balance at December 31, 2020
ASSETS		
Current Assets		
Cash and cash equivalents	$ 165	$ 261
Restricted Cash	16	143
Accounts receivable		
Customers (net of allowance for doubtful accounts of $171 million and $146 million at respective dates) (includes $2.06 billion and $1.63 billion related to VIEs, net of allowance for doubtful accounts of $171 million and $143 million at respective dates)	2,345	1,883
Accrued unbilled revenue (includes $1.09 billion and $959 million related to VIEs at respective dates)	1,207	1,083
Regulatory balancing accounts	2,999	2,001
Other	1,932	1,180
Regulatory assets	496	410
Inventories		
Gas stored underground and fuel oil	44	95
Materials and supplies	552	533
Wildfire fund asset	461	464
Other	869	1,321
Total current assets	**11,086**	**9,374**
Property, Plant, and Equipment		
Electric	69,482	66,982
Gas	25,979	24,135
Construction work in progress	3,480	2,757
Financing lease	18	18
Total property, plant, and equipment	**98,959**	**93,892**
Accumulated depreciation	(29,131)	(27,756)
Net property, plant, and equipment	**69,828**	**66,136**
Other Noncurrent Assets		
Regulatory assets	9,207	8,978
Nuclear decommissioning trusts	3,798	3,538
Operating lease right of use asset	1,232	1,736
Wildfire fund asset	5,313	5,816
Income taxes receivable	7	66
Other (includes net noncurrent accounts receivable of $187 million and $0 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $0 at respective dates)	2,706	1,818
Total other noncurrent assets	**22,263**	**21,952**
TOTAL ASSETS	**$ 103,177**	**$ 97,462**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31,	
	2021	**2020**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,184	$ 3,547
Long-term debt, classified as current (includes $18 million and $0 related to VIEs at respective dates)	4,455	—
Accounts payable		
Trade creditors	2,853	2,366
Regulatory balancing accounts	1,121	1,245
Other	648	624
Operating lease liabilities	467	530
Disputed claims and customer refunds	—	242
Interest payable	430	444
Wildfire-related claims	2,722	2,250
Other	2,430	2,248
Total current liabilities	**17,310**	**13,496**
Noncurrent Liabilities		
Long-term debt (includes $1.82 billion and $1.0 billion related to VIEs at respective dates)	33,632	32,664
Regulatory liabilities	11,999	10,424
Pension and other postretirement benefits	764	2,328
Asset retirement obligations	5,298	6,412
Deferred income taxes	3,409	1,570
Operating lease liabilities	810	1,206
Other	4,345	3,886
Total noncurrent liabilities	**60,257**	**58,490**
Contingencies and Commitments (Notes 14 and 15)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	28,286	28,286
Reinvested earnings	(4,247)	(4,385)
Accumulated other comprehensive loss	(9)	(5)
Total shareholders' equity	**25,610**	**25,476**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 103,177**	**$ 97,462**

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2021	**2020**	**2019**
Cash Flows from Operating Activities			
Net income (loss)	$ 138	$ 411	$ (7,622)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	3,403	3,469	3,233
Bad Debt Expense	154	150	46
Allowance for equity funds used during construction	(133)	(140)	(79)
Deferred income taxes and tax credits, net	1,846	1,141	(2,952)
Reorganization items, net (Note 2)	(41)	(90)	97
Wildfire fund expense	517	413	—
Disallowed capital expenditures	—	17	581
Other	172	220	121
Effect of changes in operating assets and liabilities:			
Accounts receivable	(584)	(1,160)	(132)
Wildfire-related insurance receivable	(723)	1,564	35
Inventories	(32)	6	(80)
Accounts payable	44	(24)	579
Wildfire-related claims	472	(16,525)	(114)
Income taxes receivable/payable	—	—	5
Other current assets and liabilities	251	(1,141)	101
Regulatory assets, liabilities, and balancing accounts, net	(2,266)	(2,451)	(1,417)
Liabilities subject to compromise	—	401	12,194
Contributions to Wildfire fund	(193)	(5,200)	—
Other noncurrent assets and liabilities	(577)	(108)	214
Net cash provided by (used in) operating activities	**2,448**	**(19,047)**	**4,810**
Cash Flows from Investing Activities			
Capital expenditures	(7,689)	(7,690)	(6,313)
Proceeds from sale of the SFGO	749	—	—
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,678	1,518	956
Purchases of nuclear decommissioning trust investments	(1,702)	(1,590)	(1,032)
Intercompany note to PG&E Corporation	(145)	—	—
Other	59	14	11
Net cash used in investing activities	**(7,050)**	**(7,748)**	**(6,378)**
Cash Flows from Financing Activities			
Proceeds from debtor-in-possession credit facility	—	500	1,850
Repayments of debtor-in-possession credit facility	—	(2,000)	(350)
Debtor-in-possession credit facility debt issuance costs	—	(6)	(97)
Bridge facility financing fees	—	(33)	—
Borrowings under credit facilities	9,730	8,554	—
Repayments under credit facilities	(9,976)	(3,949)	—
Credit facilities financing fees	(9)	(22)	—

Short-term debt financing, net of issuance costs of $1, $2, and $0 at respective dates	300	1,448	—
Short-term debt matured	(1,450)	—	—
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $43, $88, and $0 at respective dates	5,474	8,837	—
Repayment of long-term debt	(59)	(100)	—
Proceeds from sale of future revenue from transmission tower license sales, net of fees	370	—	—
Exchanged debt financing fees	—	(103)	—
Equity contribution from PG&E Corporation	—	12,986	—
Other	(1)	(42)	(8)
Net cash provided by financing activities	**4,379**	**26,070**	**1,395**
Net change in cash, cash equivalents, and restricted cash	**(223)**	**(725)**	**(173)**
Cash, cash equivalents, and restricted cash at January 1	**404**	**1,129**	**1,302**
Cash, cash equivalents, and restricted cash at December 31	**$ 181**	**$ 404**	**$ 1,129**
Less: Restricted cash and restricted cash equivalents	(16)	(143)	(7)
Cash and cash equivalents at December 31	**$ 165**	**$ 261**	**$ 1,122**
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest, net of amounts capitalized	$ (1,198)	$ (1,458)	$ (7)
Income taxes, net	99	—	—
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$ 1,311	$ 515	$ 826
Operating lease liabilities arising from obtaining ROU assets	100	13	2,807
Common stock equity infusion from PG&E Corporation used to satisfy liabilities	—	6,750	—

See accompanying Notes to the Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2018	**$ 258**	**$ 1,322**	**$ 8,550**	**$ 2,826**	**$ (1)**	**$ 12,955**
Net loss	—	—	—	(7,622)	—	(7,622)
Other comprehensive income	—	—	—	—	2	2
Balance at December 31, 2019	**$ 258**	**$ 1,322**	**$ 8,550**	**$ (4,796)**	**$ 1**	**$ 5,335**
Net income	—	—	—	411	—	411
Other comprehensive loss	—	—	—	—	(6)	(6)
Equity Contribution	—	—	19,736	—	—	19,736
Balance at December 31, 2020	**$ 258**	**$ 1,322**	**$ 28,286**	**$ (4,385)**	**$ (5)**	**$ 25,476**
Net income	—	—	—	138	—	138
Other comprehensive loss	—	—	—	—	(4)	(4)
Balance at December 31, 2021	**$ 258**	**$ 1,322**	**$ 28,286**	**$ (4,247)**	**$ (9)**	**$ 25,610**

See accompanying Notes to the Consolidated Financial Statements.

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, wildfire-related 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.

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 Emergence 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.

On June 20, 2020, the Bankruptcy Court entered the Confirmation Order confirming the Plan filed on June 19, 2020. PG&E Corporation and the Utility emerged from Chapter 11 on the Emergence Date of July 1, 2020.

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.

Unresolved Chapter 11 Claims

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 a trust for the benefit of holders of certain subrogation claims (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, 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. Amounts expected to be allowed are reflected as current liabilities in the Consolidated Balance Sheets.

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 Emergence Date, including claims arising from or relating to indemnification or contribution claims, including with respect to the wildfire that began on November 8, 2018 near the city of Paradise, Butte County, California (the "2018 Camp fire"), the 2017 Northern California wildfires, and the wildfire that began September 9, 2015 in Amador and Calaveras counties in Northern California (the "2015 Butte fire").

In addition, Subordinated Debt Claims and HoldCo Rescission or Damage Claims (each as defined in Note 14 below) continue to be pursued against PG&E Corporation and the Utility in the claims reconciliation process in the Bankruptcy Court, and claims against certain former directors and current and former officers, as well as certain underwriters, are being pursued in the purported securities class action that is further described in Note 14 under the heading "Securities Class Action Litigation."

In addition to filing objections in the Bankruptcy Court to claims with respect to which PG&E Corporation and the Utility do not believe they have liability, PG&E Corporation and the Utility are working to resolve certain disputed general unsecured claims before a panel of mediators. On November 4, 2021, the Bankruptcy Court entered an order extending the deadline for PG&E Corporation and the Utility to object to claims to June 21, 2022, except for a claim filed by the California Department of Water Resources, for which the Bankruptcy Court set an objection deadline of March 23, 2022.

Various electricity suppliers filed claims in the Utility's 2001 prior proceeding filed under Chapter 11 of the Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. While the FERC and judicial proceedings were 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 recover on the Utility's refund claims against these electricity suppliers. After the Utility received $145 million from the California Power Exchange and various escrows that were established as part of the disputed claims settlements in December 2021, the Utility filed at the Bankruptcy Court to close out its 2001 bankruptcy case. On December 22, 2021, the Bankruptcy Court granted the motion for entry of final decree and closed the 2001 bankruptcy case. As of December 31, 2021, the Consolidated Balance Sheets reflected $0 in net claims within Disputed claims and customer refunds compared to $242 million as of December 31, 2020. The Utility expects to refund current regulatory liabilities of $422 million, reflected in Current liabilities – other on the Consolidated Balance Sheets, $145 million of which would be funded from the amounts received from the California Power Exchange and various escrows discussed above.

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 $31 million and $53 million for PG&E Corporation and the Utility, respectively, for the year ended December 31, 2021 as compared to $102 million and $400 million for PG&E Corporation and the Utility, respectively, during 2020.

Reorganization items, net for the year ended December 31, 2021 include the following:

	Year Ended December 31, 2021		
(in millions)	**Utility**	**PG&E Corporation** [1]	**PG&E Corporation Consolidated**
Debtor-in-possession financing costs	$ —	$ —	$ —
Legal and other	21	(1)	20
Interest and other	(9)	—	(9)
Total reorganization items, net	**$ 12**	**$ (1)**	**$ 11**

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

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 income	(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 through 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.

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 held restricted cash that primarily consisted of cash held in escrow to be used to pay bankruptcy related professional fees.

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 GRCs, which occur every 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 Utility also collects additional revenue requirements to recover costs that the CPUC has authorized the Utility 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)	**2021**	**2020**
Electric		
Revenue from contracts with customers		
Residential	$ 6,089	$ 5,523
Commercial	5,042	4,722
Industrial	1,493	1,530
Agricultural	1,565	1,471
Public street and highway lighting	73	69
Other [1]	(84)	(130)
Total revenue from contracts with customers - electric	14,178	13,185
Regulatory balancing accounts [2]	953	673
Total electric operating revenue	**$ 15,131**	**$ 13,858**
Natural gas		
Revenue from contracts with customers		
Residential	$ 2,759	$ 2,517
Commercial	713	597
Transportation service only	1,346	1,211
Other [1]	140	61
Total revenue from contracts with customers - gas	4,958	4,386
Regulatory balancing accounts [2]	553	225
Total natural gas operating revenue	**5,511**	**4,611**
Total operating revenues	**$ 20,642**	**$ 18,469**

[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.

Financial Assets Measured at Amortized Cost – Credit Losses

PG&E Corporation and the Utility use the current expected credit loss model to estimate the expected lifetime credit loss on financial assets measured at amortized cost. PG&E Corporation and the Utility evaluate credit risk in their portfolio of financial assets quarterly. As of December 31, 2021, PG&E Corporation and the Utility have identified the following significant categories of financial assets.

Trade Receivables

Trade receivables are represented by customer accounts. PG&E Corporation and the Utility record an allowance for doubtful accounts to recognize an estimate of expected lifetime credit losses. The allowance is determined on a collective basis based on the historical amounts written-off and an assessment of customer collectability. Furthermore, economic conditions are evaluated as part of the estimate of expected lifetime credit losses using an analysis of regional unemployment rates.

As of December 31, 2021, the allowance also included the estimated impact of the CAPP which offers financial assistance from the State of California for eligible customers in the form of a credit to the customer's bill. The Utility recorded a reduction to the allowance for doubtful accounts of approximately $207 million in the fourth quarter of 2021 as a result of the expected CAPP funding, which was received on January 27, 2022.

As of December 31, 2021, the Utility recorded $209 million of long-term accounts receivables as a result of the CPUC's June 30, 2021 final decision on bill debt relief which offers financial assistance for eligible customers in the form of a 24-month payment plan.

As of December 31, 2021, expected credit losses of $154 million were recorded in Operating and maintenance expense on the Consolidated Statements of Income for credit losses associated with trade and other receivables. The portion of expected credit losses that are deemed probable of recovery are deferred to the RUBA, CPPMA and a FERC regulatory asset. At December 31, 2021, the RUBA current balancing accounts receivable balance was $127 million, and CPPMA and FERC long-term regulatory asset balances were $30 million and $12 million, respectively.

Other Receivables and Available-For-Sale Debt Securities

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. Wildfire fund receivables are the funds available from the statewide fund established under AB 1054 for payment of eligible claims related to the 2021 Dixie fire that exceed $1.0 billion and available insurance coverage. For more information, see Note 14 below. Wildfire fund receivables risk is related to the Wildfire Fund's durability, which is a measurement of the claim-paying capacity. Lastly, PG&E Corporation and the Utility are required to determine if the fair value is below the amortized cost basis for its available-for-sale debt securities. An impairment may exist if there is an intent to sell or a requirement to sell before recovery of the amortized basis. If such an impairment exists, then PG&E Corporation and the Utility must determine whether a portion of the impairment is a result of expected credit loss.

As of December 31, 2021, expected credit losses for insurance receivables, Wildfire Fund receivables, and available-for-sale debt securities were immaterial.

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 estimated service lives of its property, plant, and equipment were as follows:

(in millions, except estimated service lives)	Estimated Service Lives (years)	Balance at December 31, 2021	2020
Electricity generating facilities [1]	5 to 75	$ 11,217	$ 12,505
Electricity distribution facilities	10 to 70	37,723	34,902
Electricity transmission facilities	15 to 75	15,516	14,414
Natural gas distribution facilities	20 to 60	14,100	12,962
Natural gas transmission and storage facilities	5 to 66	9,067	8,293
Financing lease		18	18
Construction work in progress		3,480	2,757
General plant and other	5 to 50	7,838	8,041
Total property, plant, and equipment		**98,959**	**93,892**
Accumulated depreciation		(29,131)	(27,756)
Net property, plant, and equipment [2]		**$ 69,828**	**$ 66,136**

[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.

[2] Includes $850 million of fire risk mitigation-related property, plant, and equipment securitized in accordance with AB 1054. See Note 5 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, with the exception of its securitized property, plant and equipment, which is depreciated over the life of the bond and a pattern consistent with principal payments. 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 3.82% in 2021, 3.76% in 2020, and 3.80% in 2019. 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 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 $56 million and $133 million during 2021, $35 million and $140 million during 2020, and $55 million and $79 million during 2019.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2021 and 2020, including nuclear decommissioning obligations:

(in millions)	2021	2020
ARO liability at beginning of year	$ 6,412	$ 5,854
Liabilities incurred in the current period	—	268
Revision in estimated cash flows	(1,378)	53
Accretion	287	265
Liabilities settled	(23)	(28)
ARO liability at end of year	**$ 5,298**	**$ 6,412**

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. In December 2021, the Utility submitted its updated decommissioning cost estimate to the CPUC and correspondingly decreased its ARO liabilities by $1.4 billion. The adjustment was a result of a decrease in estimated costs based on refinements to the site-specific decommissioning analysis. 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 through rates through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

The total nuclear decommissioning obligation accrued was $3.9 billion and $5.1 billion at December 31, 2021 and 2020, respectively. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $7.6 billion and $10.6 billion at December 31, 2021 and 2020, respectively.

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 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 VIEs

Receivables Securitization Program

The SPV created in connection with the Receivables Securitization Program (as defined below in Note 5 below) in October 2020 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, 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, Other noncurrent assets, and Long-term debt, respectively, on the Consolidated Balance Sheets. As of December 31, 2021, the aggregate principal amount of the loans made by the Lenders cannot exceed $1.0 billion outstanding at any time. On September 15, 2021, the Receivables Securitization Program was amended and extended to September 15, 2023.

The SPV is considered a VIE because its equity capitalization is insufficient to support its activities. 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, 2021 or is expected to be provided in the future that was not previously contractually required. As of December 31, 2021 and 2020, the SPV had net accounts receivable of $3.3 billion and $2.6 billion, respectively, and outstanding borrowings of $974 million and $1.0 billion, respectively, under the Receivables Securitization Program.

AB 1054 Securitization

PG&E Recovery Funding LLC 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 Financing Order for AB 1054, the Utility sold its right to receive revenues from the non-bypassable wildfire hardening fixed recovery charge ("Recovery Property") to PG&E Recovery Funding LLC, which, in turn, issued recovery bonds secured by the Recovery Property. On November 12, 2021, PG&E Recovery Funding LLC issued approximately $860 million of senior secured recovery bonds. The recovery bonds were issued in three tranches: (1) approximately $266 million with an interest rate of 1.46% and is due July 15, 2033, (2) approximately $160 million with an interest rate of 2.28% and is due January 15, 2038, and (3) approximately $434 million with an interest rate of 2.82% and is due July 15, 2048. The recovery bonds are scheduled to pay principal and interest semi-annually on January 15 and July 15 of each year. The final scheduled payment date is July 15, 2046. Amounts owed to bond-holders are included in Long-term debt and Long-term debt, classified as current, on the Consolidated Balance Sheets.

PG&E Recovery Funding LLC is considered a VIE because its equity capitalization is insufficient to support its operations. The most significant activities that impact the economic performance of PG&E Recovery Funding LLC are decisions made by the servicer of the Recovery Property. The Utility is considered the primary beneficiary and consolidates PG&E Recovery Funding LLC as it acts in this role as servicer. No additional financial support was provided to PG&E Recovery Funding LLC during the year ended December 31, 2021 or is expected to be provided in the future that was not previously contractually required. As of December 31, 2021, PG&E Recovery Funding LLC has outstanding borrowings of $860 million.

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, 2021, 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, 2021, it did not consolidate any of them.

Initial and Annual Contributions to the Wildfire Fund Established Pursuant to AB 1054

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 customers, (ii) $7.5 billion in initial contributions from California's three large electric IOUs and (iii) $300 million in annual contributions paid by California's three large electric IOUs for a 10-year period. The contributions from the IOUs will be effectively borne by their respective shareholders, as they will not be permitted to recover these costs through rates. The costs of the initial and annual contributions are allocated among the IOUs pursuant to a "Wildfire Fund allocation metric" set forth in AB 1054 based on land area in the applicable IOU's service territory classified as HFTDs 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).

On the Emergence 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. San Diego Gas & Electric Company and Southern California Edison made their initial contributions to the Wildfire Fund in September 2019. On December 30, 2020 and 2021, the Utility made its second and third annual contributions of $193 million each to the Wildfire Fund. As of December 31, 2021, PG&E Corporation and the Utility have seven remaining annual contributions of $193 million (based on the current Wildfire Fund allocation metric). 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.

As of December 31, 2021, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $1.1 billion in Other non-current liabilities, $461 million in current assets - Wildfire fund asset, and $5.3 billion in non-current assets - Wildfire fund asset in the Consolidated Balance Sheets. As of December 31, 2021 and December 31, 2020, the Utility recorded amortization and accretion expense of $517 million and $413 million, respectively. The amortization of the asset, accretion of the liability, and acceleration of the amortization of the asset is reflected in Wildfire Fund expense in the Consolidated Statements of Income. Expected contributions recorded in Wildfire Fund asset on the Consolidated Balance Sheets are discounted to the present value using the 10-year U.S. 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 creates annual distributions of potential losses due to fires that could be attributed to the participating electric utilities. Starting with a five-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 six years. As of December 31, 2021, a 10% change to the assumption around current and future mitigation effort effectiveness would increase the amortization period by three years assuming greater effectiveness and would decrease the amortization period by two 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 and determination of any amounts required to be reimbursed to the Wildfire Fund, 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, and 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 assess the Wildfire Fund asset for acceleration of the amortization of the asset 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 acceleration of the amortization of the asset 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' services territories since July 12, 2019, including fires for which the cause is currently unknown, which may in the future be determined to be covered by the Wildfire Fund. As of December 31, 2021, PG&E Corporation and the Utility recorded $150 million in Other noncurrent assets for Wildfire Fund receivables related to the 2021 Dixie fire and $43 million of accelerated amortization, reflected in Wildfire Fund expense.

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 below.

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, 2021 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Total**
Beginning balance	**$ (39)**	**$ 17**	**$ (22)**
Other comprehensive income before reclassifications:			
Unrecognized net actuarial gain (net of taxes of $391 and $53, respectively)	1,007	137	1,144
Regulatory account transfer (net of taxes of $390 and $53, respectively)	(1,003)	(136)	(1,139)
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 $2 and $9, respectively) [1]	4	(24)	(20)
Regulatory account transfer (net of taxes of $1 and $5, respectively) [1]	2	14	16
Net current period other comprehensive income	**6**	**1**	**7**
Ending balance	**$ (33)**	**$ 18**	**$ (15)**

[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, 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.

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, 2021 and 2020.

For the years ended December 31, 2021 and 2020, the Utility made total cash payments, including fixed and variable, of $2.4 billion and $2.5 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, 2021 and 2020, the Utility's operating leases had a weighted average remaining lease term of 6.04 years and 5.7 years and a weighted average discount rate of 6.1% 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)	**2021**	**2020**
Operating lease fixed cost	$ 578	$ 679
Operating lease variable cost	1,782	1,852
Total operating lease costs	**$ 2,360**	**$ 2,531**

At December 31, 2021, the Utility's future expected operating lease payments were as follows:

(in millions)	December 31, 2021
2022	$ 533
2023	276
2024	118
2025	111
2026	105
Thereafter	444
Total lease payments	**1,587**
Less imputed interest	(310)
Total	**$ 1,277**

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.

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 additional attachment locations on up to 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.

In addition, the Utility and SBA entered into a Pipeline Cell Site Transaction Agreement pursuant to which the Utility and SBA established terms and conditions for adding additional cell sites under the License Agreement. Pipeline Cell Sites are locations where the Utility was in the process of locating a new Cell Site for a wireless carrier at the close of the transaction.

In exchange for the exclusive license and entry into the License Agreement, SBA paid the Utility $946 million of the purchase price at the closing. On August 15, 2021, the post-closing period ended, and the final purchase price was $947 million, pursuant to the terms of the Transaction Agreement.

The Utility recorded approximately $370 million of the $947 million sales proceeds as a financing obligation, as this portion of the proceeds for existing Cell Sites represents a sale of future revenues. The Utility recorded approximately $106 million of the $947 million sales proceeds as a contract liability (deferred revenue), as a portion of proceeds with respect to the sublicensing of Cell Sites, as well as the Tower Site Agreement, represents an upfront payment for access to space on the Utility's assets. The Utility utilized a third-party discounted cash flow model based on business assumptions and estimates to determine the allocation of the purchase price between the financing obligation and deferred revenue. The financing obligation and deferred revenue are included in Other noncurrent liabilities on the Consolidated Balance Sheets.

The Utility recorded the remaining approximately $471 million ($455 million of which was noncurrent) of the sale proceeds to regulatory liabilities, for the portion that is probable to be returned to customers in accordance with existing revenue sharing practices.

The financing obligation is amortized through Electric operating revenue and Interest expense on the Consolidated Statements of Income using the effective interest method and the deferred revenue balance is amortized through Electric operating revenue ratably over the 100-year term.

Recently Adopted Accounting Standards

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. PG&E Corporation and the Utility adopted this ASU on January 1, 2021. There was no material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements and the related disclosures resulting from the adoption of this ASU.

Government Assistance

In November 2021, the FASB issued ASU No. 2021-10, Government Assistance *(Topic 832): Disclosures by Business Entities about Government Assistance*, which increases the transparency of government assistance including the disclosure of (1) the types of assistance, (2) an entity's accounting for the assistance, and (3) the effect of the assistance on an entity's financial statements. PG&E Corporation and the Utility adopted this ASU as of December 31, 2021. There was no material impact on PG&E Corporation's or the Utility's Consolidated Financial Statements and the related disclosures resulting from the adoption of this ASU.

Accounting Standards Issued But Not Yet Adopted

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 became effective for PG&E Corporation and the Utility on January 1, 2022 and will not have a material impact on the Consolidated Financial Statements and the related disclosures.

NOTE 4: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31, 2021	Balance at December 31, 2020	Recovery Period
Pension benefits [1]	$ 708	$ 2,245	Indefinitely
Environmental compliance costs	1,089	1,112	32 years
Utility retained generation [2]	133	181	6 years
Price risk management	216	204	19 years
Unamortized loss, net of gain, on reacquired debt	37	49	23 years
Catastrophic event memorandum account [3]	1,119	842	1 - 3 years
Wildfire expense memorandum account [4]	347	400	TBD years
Fire hazard prevention memorandum account [5]	75	137	1 - 3 years
Fire risk mitigation memorandum account [6]	44	66	1 - 3 years
Wildfire mitigation plan memorandum account [7]	424	390	1 - 3 years
Deferred income taxes [8]	1,849	908	51 years
Insurance premium costs [9]	207	294	3 - 4 years
Wildfire mitigation balancing account [10]	273	156	1 - 3 years
General rate case memorandum accounts [11]	—	376	1 - 2 years
Vegetation management balancing account [12]	1,411	592	1 - 3 years
COVID-19 pandemic protection memorandum accounts [13]	49	84	TBD years
Other	1,226	942	Various
Total long-term regulatory assets	**$ 9,207**	**$ 8,978**	

[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, 2021 and 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] Balance as of December 31, 2021 represents incremental wildfire claims and outside legal expenses related to the 2021 Dixie fire. Balance as of December 31, 2020 is comprised of incremental wildfire liability insurance premium costs 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 and other incremental costs associated with fire risk mitigation. 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 and the 2021 WMP for the period of January 1, 2021 through December 31, 2021. 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 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, 2021. Noncurrent balance represents costs above 115% of adopted revenue requirements, which are subject to CPUC review and approval.

[11] The GRC memorandum accounts record the difference between the gas and electric revenue requirements in effect on January 1, 2020 and through February 28, 2021 as authorized by the CPUC in December 2020. These amounts will be recovered through rates over 22 months, beginning March 1, 2021.

[12] Represents costs from routine vegetation management and EVM activities previously recorded in the FRMMA/WMPMA, and tree mortality and fire risk reduction work previously recorded in CEMA for the period January 1, 2020 through December 31, 2021. 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 certain residential and small business customers and was approved on July 27, 2020 with an effective date of March 4, 2020. As of December 31, 2021, the Utility had recorded an under-collection of $30 million, representing incremental bad debt expense over what was collected in rates for the period the CPPMA was in effect. The remaining $19 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)	**2021**	**2020**
Cost of removal obligations (1)	$ 7,306	$ 6,905
Recoveries in excess of AROs (2)	388	458
Public purpose programs (3)	946	948
Employee benefit plans (4)	1,229	995
Transmission tower wireless licenses (5)	446	—
SFGO sale (6)	343	—
Other	1,341	1,118
Total long-term regulatory liabilities	**$ 11,999**	**$ 10,424**

(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.

(5) Represents the portion of the net proceeds received from the sale of transmission tower wireless licenses that will be returned to customers. Of the $446 million, $311 million and $135 million will be refunded to FERC and CPUC jurisdiction customers, respectively. See Note 3 above.

(6) Represents the noncurrent portion of the net gain on the sale of the SFGO, which closed on September 17, 2021, that will be distributed to customers over a five-year period, beginning in 2022.

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 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)	**2021**	**2020**
Gas distribution and transmission	$ —	$ 102
Energy procurement	310	413
Public purpose programs	321	292
Fire hazard prevention memorandum account	50	121
Fire risk mitigation memorandum account	14	33
Wildfire mitigation plan memorandum account	67	161
Wildfire mitigation balancing account	91	27
General rate case memorandum accounts	468	313
Vegetation management balancing account	127	115
Insurance premium costs	605	135
Wildfire expense memorandum account	440	—
Residential uncollectibles balancing accounts	127	—
Other	379	289
Total regulatory balancing accounts receivable	**$ 2,999**	**$ 2,001**

	Payable Balance at December 31,	
(in millions)	**2021**	**2020**
Electric distribution	$ 121	$ 55
Electric transmission	24	267
Gas distribution and transmission	83	76
Energy procurement	211	158
Public purpose programs	259	410
Nuclear decommissioning adjustment mechanism	137	—
Other	286	279
Total regulatory balancing accounts payable	**$ 1,121**	**$ 1,245**

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 CPUC-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 GRC memorandum accounts track the difference between the revenue requirements in effect on January 1, 2021 and the revenue requirements authorized in the final decision for the 2020 GRC. The VMBA tracks routine and EVM 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, 2021, there was $82 million in insurance premium costs recorded in Current regulatory assets. The WEMA balancing accounts track insurance premium costs paid by the Utility between July 26, 2017 through December 31, 2019 that are incremental to those authorized in the 2017 GRC. On October 21, 2021, the CPUC adopted a final decision approving a settlement agreement among the Utility and other active parties that authorized the Utility to recover $445.5 million over a 12-month period beginning January 1, 2022. The RUBA tracks costs associated with customer protections, including higher uncollectible costs related to a moratorium on electric and gas service disconnections for residential customers. The nuclear decommissioning adjustment mechanism tracks costs related to the closure of the Diablo Canyon power plant.

NOTE 5: DEBT

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, 2021:

(in millions)	Termination Date	Maximum Facility Limit	Loans Outstanding	Letters of Credit Outstanding	Facility Availability
Utility revolving credit facility	June 2026	$ 4,000 (1)	$ 1,885	$ 692	$ 1,423
Utility term loan credit facility	October 2022 (2)	1,441 (2)	1,441 (2)	—	—
Utility receivables securitization program (3)	September 2023	1,000 (4)	974	—	— (4)
PG&E Corporation revolving credit facility	June 2024	500	—	—	500
Total credit facilities		**$ 6,941**	**$ 4,300**	**$ 692**	**$ 1,923**

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

(2) On February 8, 2022, the Utility amended the Utility Term Loan Credit Agreement to, among other things, extend the maturity date of the 18-Month Tranche Loans to January 1, 2023 for those lenders who consented to such extension; the 18-Month Tranche Loans of the non-consenting lenders in an amount equal to $142.5 million were paid in full as of February 8, 2022.

(3) On October 5, 2020, the Utility 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. On September 15, 2021, the Receivables Securitization Program was amended and extended to September 15, 2023. For more information, see "Variable Interest Entities" in Note 3 above.

(4) The amount the Utility may borrow under the Receivables Securitization Program is limited to the lesser of the facility limit and the facility availability. The facility availability may vary based on the amount of accounts receivable that the Utility owns that are eligible for sale to the SPV and the portion of those accounts receivable that are sold to the SPV that are eligible for advances by the lenders under the Receivables Securitization Program. As of December 31, 2021, the Receivables Securitization Program had a maximum borrowing base of $974 million and was fully drawn.

Utility

As previously disclosed, on July 1, 2020, the Utility entered into a $3.5 billion revolving credit agreement (the "Utility Revolving Credit Agreement") with JPMorgan Chase Bank, N.A. and Citibank, N.A. as co-administrative agents, and Citibank, N.A., as designated agent. The Utility Revolving Credit Agreement had an initial maturity date of July 1, 2023, subject to two one-year extensions at the option of the Utility.

As previously disclosed, on June 22, 2021, the Utility amended the Utility Revolving Credit Agreement to, among other things, (i) increase the aggregate commitments provided by the lenders thereunder to $4.0 billion, (ii) extend the maturity date of such agreement to June 22, 2026 (subject to two one-year extensions at the option of the Utility), and (iii) provide for reduced interest rates and commitment fee rates based on the credit rating of the Utility.

As previously disclosed, on July 1, 2020, the Utility entered into a $3.0 billion term loan credit agreement (the "Utility Term Loan Credit Agreement") comprised of 364-day tranche loans in the aggregate principal amount of $1.5 billion (the "364-Day Tranche Loans") and 18-month tranche loans in the aggregate principal amount of $1.5 billion (the "18-Month Tranche Loans"). As previously disclosed, the 364-Day Tranche Loans were paid in full on March 11, 2021. The 18-Month Tranche Loans had an initial maturity date of 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 transactions contemplated under the Plan.

On October 29, 2021 and on December 31, 2021, the Utility amended the Utility Term Loan Credit Agreement to, among other things, extend the maturity date of the 18-Month Tranche Loans to October 1, 2022. On February 8, 2022, the Utility amended the Utility Term Loan Credit Agreement to, among other things, extend the maturity date of the 18-Month Tranche Loans to January 1, 2023 for those lenders who consented to such extension; the 18-Month Tranche Loans of the non-consenting lenders in an amount equal to $142.5 million were paid in full as of February 8, 2022. To the extent that any 18-Month Tranche Loans remain outstanding on April 1, 2022, a fee will be due and owing to the lenders holding such 18-Month Tranche Loans.

PG&E Corporation

As previously disclosed, on July 1, 2020, PG&E Corporation entered into a $500 million revolving credit agreement (the "Corporation Revolving Credit Agreement"). The Corporation Revolving Credit Agreement had a maturity date of July 1, 2023, (subject to two one-year extensions at the option of PG&E Corporation). Any future 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.

As previously disclosed, on June 22, 2021, PG&E Corporation amended the Corporation Revolving Credit Agreement to, among other things, (i) extend the maturity date of such agreement to June 22, 2024 (subject to two one-year extensions at the option of PG&E Corporation) and (ii) modify both the interest rate pricing grid and commitment fee pricing grid.

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.

Intercompany Note Payable

On August 11, 2021, PG&E Corporation borrowed $145 million from the Utility under an interest bearing 364-day intercompany note due August 10, 2022. The intercompany note includes usual and customary provisions for notes of this type. The interest rate on the loan is a variable rate equal to the interest rate applicable to loans under the Corporation Revolving Credit Agreement. Interest is due on the last business day of each month, commencing on August 31, 2021. The proceeds were borrowed to fund debt service obligations of PG&E Corporation. As of December 31, 2021, the intercompany note is reflected in Accounts receivable - other on the Utility's Consolidated Balance Sheet and is eliminated upon consolidation of PG&E Corporation's Consolidated Balance Sheet.

AB 1054

AB 1054 provides that certain capital expenditures may be financed using a structure that securitizes a dedicated customer charge. On February 24, 2021, the Utility filed an application with the CPUC seeking authorization, pursuant to AB 1054, for a transaction to finance, using securitization, up to $1.19 billion of fire risk mitigation capital expenditures that have been or will be incurred by the Utility in 2020 and 2021, with the final amount to be financed based on the capital expenditures incurred by the Utility prior to the securitization transaction. On June 24, 2021, the CPUC issued a financing order authorizing the issuance of up to approximately $1.2 billion of recovery bonds to recover up to $1.19 billion of fire risk mitigation capital expenditures plus an estimated $13.3 million in related upfront financing costs. On July 6, 2021, the financing order became final and non-appealable.

On November 12, 2021, PG&E Recovery Funding LLC issued approximately $860 million of senior secured recovery bonds. The recovery bonds were issued in three tranches: (1) approximately $266 million with an interest rate of 1.46% and is due July 15, 2033, (2) approximately $160 million with an interest rate of 2.28% and is due January 15, 2038, and (3) approximately $434 million with an interest rate of 2.82% and is due July 15, 2048. The net proceeds were used to fund fire risk mitigation capital expenditures that have been incurred by the Utility and incurred by PG&E Corporation on behalf of the Utility in 2020 and 2021.

For more information on PG&E Recovery Fund LLC, see "Variable Interest Entities" in Note 3 above.

SB 901

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 customers 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.

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 finance, using securitization, $7.5 billion of 2017 wildfire claims costs and create a corresponding customer credit trust that is designed to not impact amounts billed to customers, with the proceeds of the securitization used to pay or reimburse the Utility for the payment of wildfire claims costs associated with the 2017 Northern California wildfires. In connection with the proposed transaction, the Utility would retire $6.0 billion of Utility debt. On April 23, 2021, the CPUC issued a decision finding that $7.5 billion of the Utility's 2017 catastrophic wildfire costs and expenses are stress test costs that may be financed through the issuance of recovery bonds pursuant to Public Utilities Code sections 850 et seq. The decision is being challenged by TURN.

Short-Term Debt Issuance

On November 15, 2021, the Utility completed the sale of $300 million aggregate principal amount of Floating Rate First Mortgage Bonds due November 14, 2022. The proceeds, along with the long-term debt proceeds from the First Mortgage Bonds also issued on November 15, 2021, were used for the repayment of the $1.45 billion aggregate principal amount of the Utility's Floating Rate First Mortgage Bonds due November 15, 2021.

Long-Term Debt Issuances and Redemptions

Utility

In March 2021, the Utility issued (i) $1.5 billion aggregate principal amount of 1.367% First Mortgage Bonds due March 10, 2023, (ii) $450 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031, and (iii) $450 million aggregate principal amount of 4.20% First Mortgage Bonds due June 1, 2041. The proceeds were used for (i) the prepayment of all of the $1.5 billion 364-day term loan facility (maturing June 30, 2021) outstanding under the Utility's Term Loan Credit Agreement, (ii) the repayment of all of the borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement and (iii) general corporate purposes.

In June 2021, the Utility issued $800 million aggregate principal amount of 3.0% First Mortgage Bonds due June 15, 2028. The proceeds were used for general corporate purposes, including the repayment of borrowings under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

On November 15, 2021, the Utility completed the sale of (i) $900 million aggregate principal amount of 1.70% First Mortgage Bonds due November 15, 2023 and (ii) an additional $550 million aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031 (the "2031 Bonds"). The 2031 Bonds are part of the same series of debt securities issued by the Utility in March 2021. The proceeds were used for the repayment of the $1.45 billion aggregate principal amount of the Utility's Floating Rate First Mortgage Bonds due November 15, 2021. The Utility used the remaining net proceeds for general corporate purposes, including the repayment of approximately $300 million of borrowings outstanding under the Utility's revolving credit facility pursuant to the Utility Revolving Credit Agreement.

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

(in millions)	Contractual Interest Rates	Balance at December 31, 2021	Balance at December 31, 2020
PG&E Corporation			
Term Loan - Stated Maturity: 2025	variable rate (1)	$ 2,709	$ 2,709
Senior Secured Notes due 2028	5.00%	1,000	1,000
Senior Secured Notes due 2030	5.25%	1,000	1,000
Less: current portion, net of debt issuance costs		(26)	—
Unamortized discount, net of premium and debt issuance costs		(90)	(85)
Total PG&E Corporation Long-Term Debt		**4,593**	**4,624**
Utility			
First Mortgage Bonds - Stated Maturity:			
2022	variable rate (2)	500	500
2022	1.75%	2,500	2,500
2023	1.37% - 4.25%	3,575	1,175
2024	3.40% - 3.75%	800	800
2025	3.45% - 3.50%	1,475	1,475
2026	2.95% - 3.15%	2,551	2,551
2027	2.10% - 3.30%	2,550	2,550
2028	3.00% - 4.65%	1,975	1,175
2030	4.55%	3,100	3,100
2031	2.50% - 3.25%	3,000	2,000
2040	3.30% - 4.50%	2,951	2,951
2041	4.20% - 4.50%	700	250
2042	3.75% - 4.45%	750	750
2043	4.60%	375	375
2044	4.75%	675	675
2045	4.30%	600	600
2046	4.00% - 4.25%	1,050	1,050
2047	3.95%	850	850
2050	3.50% - 4.95%	5,025	5,025
Less: current portion, net of debt issuance costs		(2,996)	—
Unamortized discount, net of premium and debt issuance costs		(190)	(182)
Total Utility First Mortgage Bonds		**31,816**	**30,170**
Recovery Bonds	1.46% - 2.82%	860	—
Less: current portion		(18)	—
Credit Facilities			
Receivables securitization program - Stated Maturity: 2023	variable rate (3)	974	1,000
18-month Term Loan - Stated Maturity: 2022	variable rate (4)	1,441	1,500
Less: current portion		(1,441)	—
Unamortized discount, net of premium and debt issuance costs		—	(6)
Total Utility Long-Term Debt		**33,632**	**32,664**
Total PG&E Corporation Consolidated Long-Term Debt		**$ 38,225**	**$ 37,288**

(1) At December 31, 2021 and 2020, the contractual LIBOR-based interest rate on the term loan was 3.50% and 5.50%, respectively.
(2) At December 31, 2021 and 2020, the contractual LIBOR-based interest rate on $500 million of the first mortgage bonds was 1.69% and 1.70%, respectively.
(3) At December 31, 2021 and 2020, the contractual LIBOR-based interest rate on the receivables securitization program was 1.30% and 1.57%, respectively.
(4) At December 31, 2021 and 2020, the contractual LIBOR-based interest rate on the term loan was 2.38% and 2.44%, respectively.

Contractual Repayment Schedule

PG&E Corporation's and the Utility's combined stated long-term debt principal repayment amounts at December 31, 2021 are reflected in the table below:

(in millions, except interest rates)	2022	2023	2024	2025	2026	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, 2021	3.50 %	3.50 %	3.50 %	3.50 %	— %	— %	3.50 %
Variable rate obligations	$ 28	$ 28	$ 28	$ 2,625	$ —	$ —	$ 2,709
Utility							
Average fixed interest rate	1.75 %	2.26 %	3.60 %	3.47 %	3.10 %	3.90 %	3.49 %
Fixed rate obligations	$ 2,500	$ 3,575	$ 800	$ 1,475	$ 2,551	$ 23,601	$ 34,502
Variable interest rate as of December 31, 2021	2.20 %	various (1)	— %	— %	— %	— %	various (1)
Variable rate obligations	$ 1,941	$ 974	$ —	$ —	$ —	$ —	$ 2,915
Total consolidated debt	**$ 4,469**	**$ 4,577**	**$ 828**	**$ 4,100**	**$ 2,551**	**$ 25,601**	**$ 42,126**

(1) At December 31, 2021, the average interest rates for the Receivables Securitization Program, the first mortgage bonds due 2022 and the 18-month term loan were 1.30%, 1.69% and 2.38% respectively.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 1,985,400,540 shares of common stock outstanding at December 31, 2021, which excludes 477,743,590 shares of common stock issued to ShareCo. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2021.

Equity Offerings

During 2020, PG&E Corporation issued approximately 16 million PG&E Corporation equity units. The equity units represent the right of the unitholders to receive, on the settlement date, between 138 million and 168 million shares of PG&E Corporation common stock. The common stock received will be based on the value of PG&E Corporation common stock over a measurement period specified in the equity units purchase contracts and subject to certain adjustments as provided therein. The settlement date of the equity unit purchase contracts is August 16, 2023, subject to acceleration or postponement as provided in the purchase contracts.

At the Market Equity Distribution Program

On April 30, 2021, PG&E Corporation entered into an Equity Distribution Agreement ("Equity Distribution Agreement") with Barclays Capital Inc., BofA Securities, Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC, as sales agents and as forward sellers (in such capacities as applicable, the "Agents" and the "Forward Sellers," respectively), and Barclays Bank PLC, Bank of America, N.A., Credit Suisse Capital LLC and Wells Fargo Bank, National Association, as forward purchasers (the "Forward Purchasers"), establishing an at the market equity distribution program, pursuant to which PG&E Corporation, through the Agents, may offer and sell from time to time shares of PG&E Corporation's common stock having an aggregate gross sales price of up to $400 million. PG&E Corporation has no obligation to offer or sell any of its common stock under the Equity Distribution Agreement and may at any time suspend offers under the Equity Distribution Agreement.

The Equity Distribution Agreement provides that, in addition to the issuance and sale of shares of common stock by PG&E Corporation to or through the Agents, PG&E Corporation may enter into forward sale agreements (collectively, the "Forward Sale Agreements") pursuant to which the relevant Forward Purchaser will borrow shares from third parties and, through its affiliated Forward Seller, offer a number of shares of common stock equal to the number of shares of common stock underlying the particular Forward Sale Agreement.

During the year ended December 31, 2021, PG&E Corporation did not sell any shares pursuant to the Equity Distribution Agreement or any Forward Sale Agreement. As of December 31, 2021, there was $400 million available under PG&E Corporation's at the market equity distribution program for future offerings.

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 DTAs 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). The 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 4.75% or more prior to the Restriction Release Date (as defined in the Amended Articles) without approval by the Board of Directors of PG&E Corporation.

On July 8, 2021, PG&E Corporation, the Utility, ShareCo and the Fire Victim Trust entered into an agreement (the "Share Exchange and Tax Matters Agreement"), pursuant to which PG&E Corporation and the Utility made a "grantor trust" election for the Fire Victim Trust effective retroactively to the inception of the Fire Victim Trust. As a result of the grantor trust election, shares of PG&E Corporation common stock owned by the Fire Victim Trust are treated as held by the Utility and, in turn attributed to PG&E Corporation for income tax purposes. Consequently, any shares owned by the Fire Victim Trust, along with any shares owned by the Utility directly, are effectively excluded from the total number of outstanding equity securities when calculating a person's Percentage Stock Ownership (as defined in the Amended Articles) for purposes of the 4.75% ownership limitation in the Amended Articles. Shares owned by ShareCo are also effectively excluded because ShareCo is a disregarded entity for income tax purposes. For example, although PG&E Corporation had 2,463,891,104 shares outstanding as of February 4, 2022, only 1,548,403,924 shares (that is, the number of outstanding shares of common stock less the number of shares held by the Fire Victim Trust, the Utility and ShareCo) count as outstanding for purposes of the ownership restrictions in the Amended Articles. As such, based on the total number of outstanding equity securities and assuming the Fire Victim Trust has not sold any shares of PG&E Corporation common stock, a person's effective Percentage Stock Ownership limitation for purposes of the Amended Articles as of February 4, 2022 was 2.98% of the outstanding shares. As of December 31, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock. On January 31, 2022, the Fire Victim Trust initiated an exchange of 40,000,000 Plan Shares for an equal number of New Shares in the manner contemplated by the Share Exchange and Tax Matters Agreement and announced that it had entered into a transaction for the sale of these shares.

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.

Share Exchange and Tax Matters Agreement

In accordance with the Share Exchange and Tax Matters Agreement, the grantor trust election has been filed.

With the grantor trust election, the Utility's tax deductions occur as and when the Fire Victim Trust pays the fire victims rather than when the Utility transferred cash and other property (including PG&E Corporation common stock) to the Fire Victim Trust. For PG&E Corporation common stock transferred to the Fire Victim Trust, the amount of the tax deduction 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 transferred to the Fire Victim Trust.

Under the Share Exchange and Tax Matters Agreement, the parties agreed to exchange the 477,743,590 shares of PG&E Corporation common stock issued to the Fire Victim Trust pursuant to the Plan (the "Plan Shares") for an equal number of newly-issued shares of PG&E Corporation common stock (the "New Shares"). Accordingly, on July 9, 2021, PG&E Corporation issued 477,743,590 New Shares to ShareCo, which has the sole purpose of holding the New Shares in a designated brokerage account to facilitate the exchange process. When the Fire Victim Trust desires to sell any or all of its Plan Shares, the Fire Victim Trust may exchange any number of Plan Shares for a corresponding number of New Shares on a share-for-share basis (without any further consideration payable by either party) and thereafter promptly dispose of the New Shares in one or more transactions with one or more third parties. In the event that the Fire Victim Trust is unable to timely dispose of New Shares under certain circumstances (such shares, the "Nonconforming New Shares"), PG&E Corporation has authorized up to 250,000,000 additional shares of PG&E Corporation common stock, which may be transferred by ShareCo to the Fire Victim Trust on behalf of the Utility, in exchange for the Nonconforming New Shares, following the same procedures as for an exchange of Plan Shares for New Shares. The Plan Shares and any Non-Conforming New Shares exchanged will be held thereafter by the Utility. In the event that the Fire Victim Trust disposes of any share of PG&E Corporation's common stock subject to the Share Exchange and Tax Matters Agreement without complying with the terms of the agreement, the Fire Victim Trust may be required to make a payment to the Utility designed to compensate the Utility for adverse tax consequences arising from nonconforming sale transactions.

Upon PG&E Corporation's issuance of the New Shares to ShareCo, PG&E Corporation's common stock increased by $4.85 billion, the fair value of the shares on July 9, 2021. The increase to common stock is fully offset by the fair value of treasury stock recorded. The issuance of the New Shares did not have an impact on the total number of outstanding common shares as the New Shares are currently held by ShareCo and as such, there was no impact on basic or diluted EPS for the year ended December 31, 2021.

When the Fire Victim Trust notifies the Utility that it intends to sell shares, ShareCo (on behalf of the Utility) will transfer the New Shares to the Fire Victim Trust, and the Fire Victim Trust will transfer the Plan Shares to the Utility. The Utility has no plan or intention to dispose of the Plan Shares at any time. As shares are exchanged with the Fire Victim Trust, the Utility will record the cost of shares and PG&E Corporation's investment under additional paid in capital and PG&E Corporation's common stock and treasury stock will decrease by the fair value per share established on July 9, 2021.

As of December 31, 2021, none of the 250,000,000 reserved shares had been issued.

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 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. As of January 31, 2022, there were $59.1 million of such cumulative and unpaid dividends on the Utility's preferred stock. 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. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, payable on May 13, 2022, to holders of record on April 29, 2022 and declared a dividend on the Utility's preferred stock totaling $3.5 million that will be accrued during the three-month period ending April 30, 2022, payable on May 15, 2022, to holders of record on April 29, 2022. It is uncertain when PG&E Corporation and the Utility will commence the payment of dividends on their common stock.

Long-Term Incentive Plan

The 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. A maximum of 91 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the LTIP, of which 58,552,722 shares were available for future awards at December 31, 2021.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2021:

(in millions)	**2021**	**2020**	**2019**
Stock Options	$ —	$ 3	$ 7
Restricted stock units	35	15	21
Performance shares	21	17	22
Total compensation expense (pre-tax)	**$ 56**	**$ 35**	**$ 50**
Total compensation expense (after-tax)	**$ 40**	**$ 25**	**$ 35**

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, 2021, there were no unrecognized compensation costs related to nonvested stock options for PG&E Corporation.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. No stock options were granted in 2021 and 2020.

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, 2021.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2021:

	Number of Stock Options	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	2,221,247	$ 7.45		$ —
Granted [1]	—	—		—
Exercised	—	—		—
Forfeited or expired	(25,413)	10.23		—
Outstanding at December 31	2,195,834	7.42	4.33	—
Vested or expected to vest at December 31	2,195,834	7.42	4.33	—
Exercisable at December 31	2,195,834	$ 7.42	4.33	$ —

[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 2021, 2020, and 2019 was $11.01, $9.25, and $18.57, respectively. The total fair value of restricted stock units that vested during 2021, 2020, and 2019 was $19 million, $31 million, and $42 million, respectively. The tax detriment from restricted stock units that vested in 2021 was $11 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, 2021, $81 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 2.19 years.

The following table summarizes restricted stock unit activity for 2021:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	890,353	$ 23.05
Granted	10,352,117	11.01
Vested	(743,672)	25.20
Forfeited	(408,423)	11.67
Nonvested at December 31	**10,090,375**	$ 11.00

Performance Shares

Performance shares generally will vest three years after the grant date. Following 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 ("TSR") or an internal PG&E Corporation metric (subject in some instances to a multiplier based on TSR). Dividend equivalents, if any, 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 TSR-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 2021, 2020, and 2019 was $11.83, $9.62, and $15.39 respectively. The tax detriment from performance shares that vested in 2021 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, 2021, $50 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.47 years.

The following table summarizes activity for performance shares in 2021:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	7,288,782	$ 9.16
Granted	2,714,645	11.83
Vested	—	—
Forfeited [1]	(1,436,418)	11.35
Nonvested at December 31	**8,567,009**	$ 9.64

[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, 2021 and 2020, 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, respectively. The Utility's preferred stock outstanding are not subject to mandatory redemption. No shares of $100 first preferred stock are outstanding.

On December 31, 2021, 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, 2021, 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. On February 8, 2022, the Board of Directors of the Utility authorized the payment of all cumulative and unpaid dividends on the Utility's preferred stock as of January 31, 2022 totaling $59.1 million, payable on May 13, 2022, to holders of record on April 29, 2022 and declared a dividend on the Utility's preferred stock totaling $3.5 million that will be accrued during the three-month period ending April 30, 2022, payable on May 15, 2022, to holders of record on April 29, 2022.

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 2021, 2020, and 2019.

	Year Ended December 31,		
(in millions, except per share amounts)	**2021**	**2020**	**2019**
Loss attributable to common shareholders	$ (102)	$ (1,318)	$ (7,656)
Weighted average common shares outstanding, basic	1,985	1,257	528
Add incremental shares from assumed conversions:			
Employee share-based compensation	—	—	—
Equity Units	—	—	—
Weighted average common share outstanding, diluted	1,985	1,257	528
Total Loss per common share, diluted	**$ (0.05)**	**$ (1.05)**	**$ (14.50)**

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 DTAs and liabilities. DTAs 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 technical 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)	**2021**	**2020**	**2019**	**2021**	**2020**	**2019**
Current:						
Federal	$ —	$ (26)	$ 1	$ —	$ (26)	$ 4
State	1	(34)	101	—	(34)	94
Deferred:						
Federal	543	258	(2,361)	588	290	(2,363)
State	296	171	(1,136)	316	185	(1,137)
Tax credits	(4)	(7)	(5)	(4)	(7)	(5)
Income tax provision (benefit)	**$ 836**	**$ 362**	**$ (3,400)**	**$ 900**	**$ 408**	**$ (3,407)**

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

(in millions)	PG&E Corporation 2021	PG&E Corporation 2020	Utility 2021	Utility 2020
	Year Ended December 31,			
Deferred income tax assets:				
Tax carryforwards	$ 5,628	$ 7,641	$ 5,425	$ 7,529
Compensation	185	187	108	109
Wildfire-related claims [1]	1,723	544	1,723	544
Operating lease liability	346	489	346	488
Transmission tower wireless licenses	266	—	266	—
Other [2]	278	212	293	219
Total deferred income tax assets	**$ 8,426**	**$ 9,073**	**$ 8,161**	**$ 8,889**
Deferred income tax liabilities:				
Property related basis differences	8,847	8,311	8,835	8,300
Regulatory balancing accounts	1,193	763	1,193	763
Debt financing costs	501	526	501	526
Operating lease right of use asset	346	489	346	488
Income tax regulatory asset [3]	517	254	517	254
Other [4]	199	128	178	128
Total deferred income tax liabilities	**$ 11,603**	**$ 10,471**	**$ 11,570**	**$ 10,459**
Total net deferred income tax liabilities	**$ 3,177**	**$ 1,398**	**$ 3,409**	**$ 1,570**

[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 in 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 2021	PG&E Corporation 2020	PG&E Corporation 2019	Utility 2021	Utility 2020	Utility 2019
	Year Ended December 31,					
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]	31.3	(15.3)	7.5	24.1	19.1	7.5
Effect of regulatory treatment of fixed asset differences [2]	(71.5)	39.0	2.8	(51.6)	(44.9)	2.8
Tax credits	(1.7)	1.5	0.1	(1.2)	(1.7)	0.1
Fire Victim Trust [3]	127.3	(44.9)	—	91.9	51.7	—
Bankruptcy and emergence	—	(37.6)	—	—	2.4	—
Other, net [4]	5.3	(2.1)	(0.6)	2.6	2.2	(0.5)
Effective tax rate	**111.7 %**	**(38.4)%**	**30.8 %**	**86.8 %**	**49.8 %**	**30.9 %**

(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 2021, 2020, and 2019, 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 a DTA write-off associated with the grantor trust election for the Fire Victim Trust in 2021 and an adjustment for the DTA write-off for 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 in 2020. PG&E Corporation includes the same adjustment as the Utility in 2021 and 2020 as well as a permanent non-deductible equity backstop premium expense in 2020. This combined with a pre-tax loss and a pre-tax income for PG&E Corporation and the Utility, respectively in 2020, accounts for the remaining difference.
(4) These amounts primarily represent the impact of tax audit settlements and non-tax deductible penalty costs in 2021 and 2020.

Unrecognized Tax Benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	**2021**	**2020**	**2019**	**2021**	**2020**	**2019**
Balance at beginning of year	$ 437	$ 420	$ 377	$ 437	$ 420	$ 377
Reductions for tax position taken during a prior year	(23)	(43)	(1)	(23)	(43)	(1)
Additions for tax position taken during the current year	85	60	44	85	60	44
Settlements	(1)	—	—	(1)	—	—
Balance at end of year	**$ 498**	**$ 437**	**$ 420**	**$ 498**	**$ 437**	**$ 420**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2021 for PG&E Corporation and the Utility was $30 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, 2021, 2020, and 2019, 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.

PG&E Corporation's tax returns have been accepted through 2014 for California income tax purposes. Tax years 2015 and thereafter 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, 2021	Expiration Year
Federal:			
Net operating loss carryforward - Pre-2018	$	3,600	2031 - 2036
Net operating loss carryforward - Post-2017		17,467	N/A
Tax credit carryforward		144	2029 - 2041
State:			
Net operating loss carryforward	$	18,853	2039 - 2041
Tax credit carryforward		122	Various

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, 2021, 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, 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 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. Half of the payment was paid in 2021.

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.

Additionally, as a result of the grantor trust election, the Utility's tax deductions occur when the Fire Victim Trust pays the fire victims, rather than when the Utility transferred cash and other property (including PG&E Corporation common stock) to the Fire Victim Trust. Therefore, $5.4 billion of cash and $4.54 billion of PG&E Corporation common stock, in the aggregate $10.0 billion, that were transferred to the Fire Victim Trust in 2020, will not be deductible for tax purposes by the Utility until the Fire Victim Trust pays the fire victims. Furthermore, the activities of the Fire Victim Trust are treated as activities of the Utility for tax purposes. PG&E Corporation's net operating loss has decreased by approximately $10.0 billion, which will be offset by payments made by the Fire Victim Trust to the fire victims (which totaled approximately $1.67 billion in 2021) and the net activities of the Fire Victim Trust to date. Additionally, there was a $1.3 billion charge, net of tax, decreasing net DTAs for the payment made to the Fire Victim Trust in PG&E Corporation common stock on its Consolidated Financial Statements for activity through December 31, 2020. PG&E Corporation will recognize income tax benefits and the corresponding DTA as the Fire Victim Trust sells shares of PG&E Corporation common stock, and the amounts of such benefits and assets 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 transferred to the Fire Victim Trust. As of December 31, 2021, to the knowledge of PG&E Corporation, the Fire Victim Trust had not sold any shares of PG&E Corporation common stock, resulting in no tax impact in PG&E Corporation's and the Utility's consolidated financial statements for the year ended December 31, 2021. On January 31, 2022, the Fire Victim Trust initiated an exchange of 40,000,000 Plan Shares for an equal number of New Shares in the manner contemplated by the Share Exchange and Tax Matters Agreement and announced that it had entered into a transaction for the sale of these shares. For more information, see Note 6 above.

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 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 through 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	2021	2020
Natural Gas [1] (MMBtus [2])	Forwards, Futures and Swaps	173,361,635	146,642,863
	Options	14,420,000	14,140,000
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	10,283,639	9,435,830
	Options	288,000	—
	Congestion Revenue Rights [3]	239,857,610	266,091,470

[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, 2021, 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	$ 58	$ (9)	$ 152	$ 201
Other noncurrent assets – other	169	—	—	169
Current liabilities – other	(53)	9	18	(26)
Noncurrent liabilities – other	(216)	—	—	(216)
Total commodity risk	**$ (42)**	**$ —**	**$ 170**	**$ 128**

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

(in millions)	Commodity Risk 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**

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, 2021, 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, 2021				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Assets:					
Short-term investments	$ 289	$ —	$ —	$ —	**$ 289**
Nuclear decommissioning trusts					
Short-term investments	22	—	—	—	**22**
Global equity securities	2,504	—	—	—	**2,504**
Fixed-income securities	1,158	866	—	—	**2,024**
Assets measured at NAV	—	—	—	—	**31**
Total nuclear decommissioning trusts [2]	**3,684**	**866**	**—**	**—**	**4,581**
Price risk management instruments (Note 10)					
Electricity	—	9	214	6	**229**
Gas	—	4	—	137	**141**
Total price risk management instruments	**—**	**13**	**214**	**143**	**370**
Rabbi trusts					
Fixed-income securities	—	104	—	—	**104**
Life insurance contracts	—	76	—	—	**76**
Total rabbi trusts	**—**	**180**	**—**	**—**	**180**
Long-term disability trust					
Short-term investments	6	—	—	—	**6**
Assets measured at NAV	—	—	—	—	**132**
Total long-term disability trust	**6**	**—**	**—**	**—**	**138**
TOTAL ASSETS	**$ 3,979**	**$ 1,059**	**$ 214**	**$ 143**	**$ 5,558**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ —	$ 11	$ 248	$ (24)	**$ 235**
Gas	—	10	—	(3)	**7**
TOTAL LIABILITIES	**$ —**	**$ 21**	**$ 248**	**$ (27)**	**$ 242**

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and cash collateral.
[2] Represents amount before deducting $783 million, primarily related to deferred taxes on appreciation of investment value.

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

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, 2021 and 2020.

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, credit 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 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, 2021**				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [(1)]/Weighted-Average Price [(2)]**
Congestion revenue rights	$ 188	$ 93	Market approach	CRR auction prices	$ (40.77) - 2,265.94 / 0.40
Power purchase agreements	$ 26	$ 155	Discounted cash flow	Forward prices	$ (7.97) - 256.20 / 47.17

(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, 2020				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**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.

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2021 and 2020, respectively:

(in millions)	Price Risk Management Instruments 2021	2020
Asset (liability) balance as of January 1	**$ (72)**	**$ 5**
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [(1)]	38	(77)
Asset (liability) balance as of December 31	**$ (34)**	**$ (72)**

(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, 2021 and 2020, 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,			
	2021		2020	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 5)				
PG&E Corporation	$ 4,619	$ 4,796	$ 1,901	$ 2,175
Utility	31,816	35,803	29,664	32,632

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, 2021				
Nuclear decommissioning trusts				
Short-term investments	$ 22	$ —	$ —	$ 22
Global equity securities	479	2,066	(10)	2,535
Fixed-income securities	1,938	98	(12)	2,024
Total [(1)]	**$ 2,439**	**$ 2,164**	**$ (22)**	**$ 4,581**
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**

(1) Represents amounts before deducting $783 million and $671 million at December 31, 2021 and 2020, 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, 2021
Less than 1 year	$ 97
1–5 years	495
5–10 years	480
More than 10 years	952
Total maturities of fixed-income securities	**$ 2,024**

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

(in millions)	2021	2020	2019
Proceeds from sales and maturities of nuclear decommissioning investments	$ 1,678	$ 1,518	$ 956
Gross realized gains on securities	286	159	69
Gross realized losses on securities	(19)	(41)	(14)

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 IRC. 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 plan up to the amount it is authorized to recover through 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 2021 and 2020:

Pension Plan

(in millions)	2021	2020
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 20,759**	**$ 18,547**
Actual return on plan assets	1,693	2,736
Company contributions	335	343
Benefits and expenses paid	(892)	(867)
Fair value of plan assets at end of year	**$ 21,895**	**$ 20,759**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 23,172**	**$ 20,525**
Service cost for benefits earned	587	530
Interest cost	645	713
Actuarial (gain) loss [1]	(752)	2,271
Plan amendments	—	—
Benefits and expenses paid	(893)	(867)
Benefit obligation at end of year [2]	**$ 22,759**	**$ 23,172**
Funded Status:		
Current liability	$ (9)	$ (3)
Noncurrent liability	(856)	(2,410)
Net liability at end of year	**$ (865)**	**$ (2,413)**

(1) The actuarial gain for the year ended December 31, 2021 was due to an increase in the discount rate used to measure the projected benefit obligation, offset by unfavorable changes in the demographic assumptions. The actuarial loss for the year ended December 31, 2020 was due to a decrease in the discount rate used to measure the projected benefit obligation.

(2) PG&E Corporation's accumulated benefit obligation was $20.4 billion and $20.7 billion at December 31, 2021 and 2020, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2021	2020
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,995**	**$ 2,678**
Actual return on plan assets	193	379
Company contributions	10	26
Plan participant contribution	80	81
Benefits and expenses paid	(176)	(169)
Fair value of plan assets at end of year	**$ 3,102**	**$ 2,995**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,876**	**$ 1,832**
Service cost for benefits earned	63	61
Interest cost	51	63
Actuarial gain [1]	(152)	(14)
Benefits and expenses paid	(156)	(149)
Federal subsidy on benefits paid	4	3
Plan participant contributions	80	80
Benefit obligation at end of year	**$ 1,766**	**$ 1,876**
Funded Status: [2]		
Noncurrent asset	$ 1,340	$ 1,153
Noncurrent liability	(4)	(34)
Net asset at end of year	**$ 1,336**	**$ 1,119**

(1) The actuarial gain for the year ended December 31, 2021 was primarily due to an increase in the discount rate used to measure the accumulated benefit obligations and favorable claims cost changes. 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.

(2) At December 31, 2021 and 2020, 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 $363 million and $359 million as of December 31, 2021, and $377 million and $343 million as of December 31, 2020, 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)	2021	2020	2019
Service cost for benefits earned [1]	$ 587	$ 530	$ 443
Interest cost	645	713	758
Expected return on plan assets	(1,046)	(1,044)	(906)
Amortization of prior service cost	(6)	(6)	(6)
Amortization of net actuarial loss	6	3	3
Net periodic benefit cost	**186**	**196**	**292**
Less: transfer to regulatory account [2]	147	136	42
Total expense recognized	**$ 333**	**$ 332**	**$ 334**

(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 through future rates.

Postretirement Benefits Other than Pensions

(in millions)	2021	2020	2019
Service cost for benefits earned (1)	$ 63	$ 61	$ 56
Interest cost	51	63	76
Expected return on plan assets	(137)	(138)	(123)
Amortization of prior service cost	14	14	14
Amortization of net actuarial loss	(33)	(21)	(3)
Net periodic benefit cost	**$ (42)**	**$ (21)**	**$ 20**

(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,		
	2021	2020	2019	2021	2020	2019
Discount rate	3.03 %	2.77 %	3.46 %	2.97 - 3.04%	2.67 - 2.80 %	3.37 - 3.47%
Rate of future compensation increases	3.80 %	3.80 %	3.90 %	N/A	N/A	N/A
Expected return on plan assets	5.50 %	5.10 %	5.70 %	3.30 - 6.40%	3.10 - 6.10 %	3.50 - 6.60%
Interest crediting rate for cash balance plan	1.95 %	1.95 %	2.11 %	N/A	N/A	N/A

The assumed health care cost trend rate as of December 31, 2021 was 6.0%, 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 5.5% 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 817 Aa-grade non-callable bonds at December 31, 2021. 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 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**		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
Global equity securities	30 %	30 %	30 %	26 %	36 %	28 %
Absolute return	2 %	2 %	2 %	1 %	1 %	2 %
Real assets	8 %	8 %	8 %	3 %	5 %	8 %
Fixed-income securities	60 %	60 %	60 %	70 %	58 %	62 %
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, 2021 and 2020.

	Fair Value Measurements							
	At December 31,							
	2021				2020			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Plan:								
Short-term investments	$ 552	$ 255	$ —	$ 807	$ 334	$ 408	$ —	$ 742
Global equity securities	2,074	424	—	2,498	1,875	—	—	1,875
Absolute Return	—	1	—	1	1	1	—	2
Real assets	632	—	—	632	517	—	—	517
Fixed-income securities	2,729	7,388	27	10,144	2,467	7,154	12	9,633
Assets measured at NAV	—	—	—	7,972	—	—	—	8,224
Total	**$ 5,987**	**$ 8,068**	**$ 27**	**$ 22,054**	**$ 5,194**	**$ 7,563**	**$ 12**	**$ 20,993**
PBOP Plans:								
Short-term investments	$ 31	$ —	$ —	$ 31	$ 37	$ —	$ —	$ 37
Global equity securities	105	—	—	105	173	—	—	173
Real assets	34	—	—	34	54	—	—	54
Fixed-income securities	776	875	1	1,652	481	715	1	1,197
Assets measured at NAV	—	—	—	1,296	—	—	—	1,549
Total	**$ 946**	**$ 875**	**$ 1**	**$ 3,118**	**$ 745**	**$ 715**	**$ 1**	**$ 3,010**
Total plan assets at fair value				**$ 25,172**				**$ 24,003**

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net liabilities of $175 million and $249 million at December 31, 2021 and 2020, 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 NAV 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, fixed-income securities that are composed primarily of U.S. government securities, credit securities and asset-backed securities, and real assets and absolute return investments that are held to diversify the trust's holdings in equity and fixed-income securities.

Transfers Between Levels

No material transfers between levels occurred in the years ended December 31, 2021 and 2020.

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, 2021 and 2020:

(in millions)

For the year ended December 31, 2021	**Fixed-Income**
Balance at beginning of year	$ 12
Actual return on plan assets:	
Relating to assets still held at the reporting date	6
Relating to assets sold during the period	(7)
Purchases, issuances, sales, and settlements:	
Purchases	22
Settlements	(6)
Balance at end of year	**$ 27**

(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**

There were no material transfers out of Level 3 in 2021 and 2020.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $335 million to the pension benefit plans and $10 million to the other benefit plans in 2021. 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 2021. 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 2022.

Benefits Payments and Receipts

As of December 31, 2021, 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
2022	869	81	(3)
2023	954	85	(3)
2024	988	89	(3)
2025	1018	88	(3)
2026	1,046	91	(3)
Thereafter in the succeeding five years	5,533	466	(3)

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 $133 million, $119 million, and $109 million in 2021, 2020, and 2019, 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:

(in millions)	Year Ended December 31, 2021	2020	2019
Utility revenues from:			
Administrative services provided to PG&E Corporation	$ 3	$ 3	$ 4
Utility expenses from:			
Administrative services received from PG&E Corporation	$ 82	$ 108	$ 107
Utility employee benefit due to PG&E Corporation	39	34	42

At December 31, 2021 and 2020, the Utility had receivables of $173 million and $35 million, respectively, from PG&E Corporation included in Accounts receivable – other and Noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of $19 million and $46 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

On August 11, 2021, PG&E Corporation borrowed $145 million from the Utility under an interest bearing 364-day intercompany note due August 10, 2022. As of December 31, 2021, the intercompany note is reflected in Accounts receivable - other on the Utility's Consolidated Balance Sheet and is eliminated upon consolidation of PG&E Corporation's Consolidated Balance Sheet. For more information, see "Intercompany Note Payable" in Note 5 above.

NOTE 14: WILDFIRE-RELATED CONTINGENCIES

Liability Overview

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 (including those during mediations with claimants), 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.

The process for estimating losses associated with potential claims related to wildfires 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, including from potential claimants as litigation or resolution efforts progress, management estimates and assumptions regarding the potential financial impacts of wildfire events may change.

Potential liabilities related to wildfires depend on various factors, including the cause of the fire, contributing causes of the fire (including alternative potential origins, weather- and climate-related issues, and forest management and fire suppression practices), 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 courts or other governmental entities.

Criminal charges have been filed against the Utility in connection with the 2019 Kincade fire and the 2020 Zogg fire. Under California law (including Penal Code section 1202.4), if the Utility were convicted of any of the charges, the sentencing court must order the Utility to "make restitution to the victim or victims in an amount established by court order" that is "sufficient to fully reimburse the victim or victims for every determined economic loss incurred as the result of" the Utility's underlying conduct, in addition to interest and the victim's or victims' attorneys' fees. This requirement for full reimbursement of economic loss is not waivable by either the government or the victims and is not offset by any compensation that the victims have received or may receive from their insurance carriers. If convicted of any of the charges, the Utility could be subject to fines, penalties, and restitution to victims for their economic losses (including property damage, medical and mental health expenses, lost wages, lost profits, attorneys' fees and interest), as well as non-monetary remedies such as oversight requirements. In the event that the Utility were convicted of certain charges in connection with the 2019 Kincade fire or 2020 Zogg fire, the Utility currently believes that, depending on which charges it were to be convicted of, its total losses associated with such fire would materially exceed the accrued estimated liabilities that PG&E Corporation and the Utility have recorded to reflect the lower end of the range of the reasonably estimable range of losses. The Utility is currently unable to determine a reasonable estimate of the amount of such additional losses. The Utility does not expect that any of its liability insurance would be available to cover restitution payments ordered by the courts presiding over the criminal proceedings.

PG&E Corporation and the Utility are aware of numerous civil complaints related to the following wildfire events and expect that they may receive further such complaints. The complaints 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 relevant wildfire. The timing and outcome for resolution of any such claims or investigations are uncertain. The Utility believes it will continue to receive additional information from potential claimants in connection with these wildfire events as litigation or resolution efforts progress. Any such additional information may potentially allow PG&E Corporation and the Utility to refine the estimates of their accrued losses and may result in changes to the accrual depending on the information received. PG&E Corporation and the Utility intend to vigorously defend themselves against both criminal charges and civil complaints.

If the Utility's facilities, such as its electric distribution and transmission lines, are judicially determined to be the substantial cause of the following matters, 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 through rates. 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. In addition to claims for property damage, business interruption, interest and attorneys' fees under inverse condemnation, 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 in connection with the following wildfire events, including if PG&E Corporation or the Utility were found to have been negligent.

PG&E Corporation and the Utility currently believe that it is reasonably possible that the amount of loss could be greater than the accrued estimated amounts 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 and the outcome of the criminal proceedings initiated against the Utility. If the liability for wildfires were to exceed $1.0 billion in the aggregate in any Coverage Year, the Utility may be eligible to make a claim to the Wildfire Fund under AB 1054 to satisfy settled or finally adjudicated eligible claims in excess of such amount, except that claims related to the 2019 Kincade fire would be subject to the 40% limitation on the allowed amount of 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 the possession of Cal Fire or the relevant district attorney's office, 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.

2019 Kincade Fire

According to Cal Fire, on October 23, 2019 at approximately 9:27 p.m. Pacific Time, a wildfire began northeast of Geyserville in Sonoma County, California (the "2019 Kincade fire"), located in the service territory of the Utility. According to a Cal Fire incident update dated March 3, 2020, 3:35 p.m. Pacific Time, the 2019 Kincade fire consumed 77,758 acres and resulted in no fatalities, four first responder injuries, 374 structures destroyed, and 60 structures damaged. In connection with the 2019 Kincade fire, state and local officials issued numerous mandatory evacuation orders and evacuation warnings. 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 July 16, 2020, Cal Fire issued a press release with its determination that the Utility's equipment caused the 2019 Kincade fire.

On April 6, 2021, the Sonoma County District Attorney's office filed the Kincade Complaint charging the Utility with five felonies and 28 misdemeanors related to the 2019 Kincade fire. On April 6, 2021, PG&E Corporation announced that it disputed the charges in the Kincade Complaint. It further announced that it would accept Cal Fire's finding that a Utility transmission line caused the 2019 Kincade fire. On May 11, 2021, the Utility filed a demurrer to 25 of the 33 counts contained in the Kincade Complaint. At a hearing on September 9, 2021, the Sonoma County Superior Court overruled the demurrer. The Utility pled not guilty to all charges on October 13, 2021. On January 28, 2022, the Sonoma County District Attorney's Office filed the Kincade Amended Complaint, which replaces two felonies with five different felonies and drops six misdemeanor counts. On January 28, 2022, the court deemed the Utility's demurrer and the court's prior ruling as applying to 22 of the 30 counts in the Kincade Amended Complaint, and the Utility thereafter pled not guilty to all charges in the Kincade Amended Complaint. A preliminary hearing on the charges began on February 8, 2022.

On December 2, 2021, the CPUC approved a settlement between the Safety Enforcement Division and the Utility (the "Kincade SED Settlement"). The Kincade SED Settlement resolves SED's investigation into the 2019 Kincade fire and provides for the removal of approximately 70 transmission lines or portions of lines that are no longer in service and are de-energized but have not been removed as required by CPUC rules. The Kincade SED Settlement provides that (i) the Utility will pay $40 million to California's General Fund; (ii) the Utility will remove permanently abandoned transmission lines over a ten-year period; and (iii) the Utility must incur $85 million of the costs of such work by December 31, 2024, and it may not seek recovery of this $85 million of costs. SED agreed to refrain from instituting enforcement proceedings against the Utility for not having removed the lines previously. The Kincade SED Settlement states that it does not constitute an admission by the Utility of violations of GOs or statutory requirements. In connection with the Kincade SED Settlement, PG&E Corporation and the Utility recorded a liability of $40 million reflected in Other current liabilities on the Consolidated Financial Statements for the period ended December 31, 2021. For the $85 million of cost of removal that the Utility will not seek recovery, the Utility expects to record such disallowances in 2022. On January 10, 2022, TURN filed an application for rehearing of the Kincade SED Settlement. On January 25, 2022, the Utility filed an opposition to the application for rehearing.

As of February 3, 2022, PG&E Corporation and the Utility are aware of approximately 100 complaints on behalf of at least 2,605 plaintiffs related to the 2019 Kincade fire. The plaintiffs filed master complaints on July 16, 2021; PG&E Corporation's and the Utility's response was filed on August 16, 2021; and PG&E Corporation and the Utility filed a demurrer with respect to the plaintiffs' inverse condemnation claims. On December 10, 2021, the court overruled the demurrer. In addition, on January 5, 2022, Cal Fire filed a complaint in the coordinated proceeding seeking to recover approximately $90 million for fire suppression and other costs incurred in connection with the 2019 Kincade fire. Following a November 5, 2021 hearing, the San Francisco County Superior Court set a trial date of November 7, 2022.

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 Cal Fire's determination of the cause and 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 2019 Kincade fire. PG&E Corporation and the Utility recorded a liability in the aggregate amount of $625 million for the year ended December 31, 2020 (before available insurance). Based on the facts and circumstances available to the Utility as of the filing of PG&E Corporation's and the Utility's Consolidated Financial Statements for the year ended December 31, 2021, including the status of negotiations with certain subrogation entities, PG&E Corporation and the Utility recorded an additional charge in 2021 for potential losses in connection with the 2019 Kincade fire of $175 million, for an aggregate liability of $800 million (before available insurance).

The Utility's accrued estimated losses do not include, among other things: (i) any amounts for potential penalties, fines, or restitution that may be imposed by courts or other 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 following table presents changes in the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses for claims arising from the 2019 Kincade fire since December 31, 2019.

Loss Accrual (in millions)		
Balance at December 31, 2019	**$**	**—**
Accrued Losses		625
Payments		—
Balance at December 31, 2020		**625**
Accrued Losses		175
Payments		(31)
Balance at December 31, 2021	**$**	**769**

The Utility has liability insurance coverage for third-party liability attributable to the 2019 Kincade fire in an aggregate amount of $430 million. As of December 31, 2021, the Utility has recorded an insurance receivable for the full amount of the $430 million.

2020 Zogg Fire

According to Cal Fire, on September 27, 2020, at approximately 4:03 p.m. Pacific Time, 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. According to a Cal Fire incident update dated October 16, 2020, 3:08 p.m. Pacific Time, the 2020 Zogg fire consumed 56,338 acres and resulted in four fatalities, one injury, 204 structures destroyed, and 27 structures damaged.

On March 22, 2021, Cal Fire issued a press release with its determination that the 2020 Zogg fire was caused by a pine tree contacting electrical facilities owned and operated by the Utility located north of the community of Igo.

On September 24, 2021, the Shasta County District Attorney's Office filed the Zogg Complaint charging the Utility with 11 felonies and 20 misdemeanors related to the 2020 Zogg fire, the 2020 Daniel fire, the 2020 Ponder fire, and the 2021 Woody fire. On September 24, 2021, PG&E Corporation and the Utility announced that they disputed the charges in the Zogg Complaint. They further announced that they would accept Cal Fire's finding that a Utility electric line caused the 2020 Zogg fire, even though PG&E Corporation and the Utility did not have access to all of the evidence that Cal Fire gathered. On November 18, 2021, the Utility filed a demurrer to 10 of the 31 counts contained in the Zogg Complaint. A hearing on the demurrer is set for April 4, 2022.

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.

As of February 3, 2022, PG&E Corporation and the Utility are aware of approximately 21 complaints on behalf of at least 382 plaintiffs related to 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. The plaintiffs filed master complaints on August 6, 2021, and PG&E Corporation's and the Utility's answer was filed on September 7, 2021, and PG&E Corporation and the Utility filed a demurrer with respect to the plaintiffs' inverse condemnation claims. On December 10, 2021, the court overruled the demurrer. At an October 4, 2021 hearing, the San Francisco County Superior Court set a trial date of February 6, 2023. In addition, PG&E Corporation and the Utility have been contacted by Cal Fire to accept service of a complaint filed against them for fire suppression costs incurred in connection with the 2020 Zogg fire.

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 Cal Fire's determination of the cause and 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. PG&E Corporation and the Utility recorded a liability in the aggregate amount of $275 million for the year ended December 31, 2020 (before available insurance). Based on the facts and circumstances available to the Utility as of the filing of the Consolidated Financial Statements for the year ended December 31, 2021, including the status of negotiations with certain agencies, subrogation entities, and individual plaintiffs, PG&E Corporation and the Utility recorded an additional charge in 2021 for potential losses in connection with the 2020 Zogg fire in the amount of $100 million, for an aggregate liability of $375 million (before available insurance). Following continued negotiations during the quarter ended December 31, 2021, PG&E Corporation and the Utility entered agreements with all but one of the insurance subrogation plaintiffs in the 2020 Zogg fire litigation to resolve their claims arising from the 2020 Zogg fire.

The Utility's accrued estimated losses do not include, among other things: (i) any amounts for potential penalties, fines, or restitution that may be imposed by courts or other 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 following table presents changes in the lower end of the range of PG&E Corporation's and the Utility's reasonably estimable range of losses for claims arising from the 2020 Zogg fire since December 31, 2019.

Loss Accrual (in millions)

Balance at December 31, 2019	**$**	**—**
Accrued Losses		275
Payments		—
Balance at December 31, 2020		**275**
Accrued Losses		100
Payments		(164)
Balance at December 31, 2021	**$**	**211**

The Utility has liability insurance for third-party liability attributable to the 2020 Zogg fire in an aggregate amount of $611 million. This amount is reduced from the $867.5 million of coverage disclosed in the 2020 Form 10-K due to the Utility's commuting certain insurance policies in connection with its April 2021 wildfire liability insurance renewal. As of December 31, 2021, the Utility has recorded an insurance receivable for $337 million for probable insurance recoveries in connection with the 2020 Zogg fire, which equals the $375 million probable loss estimate less an initial self-insured retention of $60 million, plus $22 million in legal fees incurred. Recovery under the Utility's insurance policies for the 2021 Dixie fire will reduce the amount of insurance proceeds available for the 2020 Zogg fire by the same amount.

2021 Dixie Fire

According to Cal Fire, on July 13, 2021, at approximately 5:15 p.m. Pacific Time, a wildfire began in the Feather River Canyon near Cresta Dam (the "2021 Dixie fire"), located in the service territory of the Utility. According to a Cal Fire incident update, dated October 25, 2021, 7:46 a.m. Pacific Time, the 2021 Dixie fire consumed 963,309 acres and resulted in 1,329 structures destroyed (including 717 residential, 143 commercial, and 443 other structures), 95 structures damaged, and one fatality, which according to published reports was a fire fighter who passed away due to COVID-19 after returning home from the 2021 Dixie fire.

On January 4, 2022, Cal Fire issued a press release with its determination that the 2021 Dixie fire was caused by a tree contacting electrical distribution lines owned and operated by the Utility.

The Butte County, Plumas County, Shasta County, Lassen County and Tehama County District Attorneys' Offices, as well as the SED and OEIS, are investigating the fire; various other entities, which may include other state and federal law enforcement agencies, may also be investigating the fire. The United States Attorney's Office for the Eastern District of California issued a subpoena for documents as well. PG&E Corporation and the Utility are cooperating with the investigations. 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 2021 Dixie fire. This investigation is ongoing, 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.

As of February 3, 2022, PG&E Corporation and the Utility are aware of approximately 20 complaints on behalf of at least 1,005 plaintiffs related to the 2021 Dixie fire and expect that they may receive further such complaints. The plaintiffs seek damages that include property damage, economic loss, punitive damages, exemplary damages, attorneys' fees and other damages.

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 Cal Fire's determination of the cause and 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 2021 Dixie fire. PG&E Corporation and the Utility recorded a liability in the aggregate amount of $1.15 billion for the year ended December 31, 2021 (before available recoveries).

The Utility's accrued estimated losses do not include, among other things: (i) any amounts for potential penalties, fines, or restitution that may be imposed by courts or other 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 including for state or federal fire suppression costs and damages related to federal land, (iv) evacuation costs, or (v) any other amounts that are not reasonably estimable.

As noted above, the aggregate estimated liability for claims in connection with the 2021 Dixie fire does not include potential claims for fire suppression costs from federal, state, county, or local agencies or damage to land and vegetation in national parks or national forests. As to these damages, PG&E Corporation and the Utility have not concluded that a loss is probable due to the incomplete information available to PG&E Corporation and the Utility as of the date of this filing as to facts pertinent to potential claims and defenses. Moreover, PG&E Corporation and the Utility are currently unable to reasonably estimate the range of possible losses for any such claims due to, among other factors, incomplete information as to facts pertinent to potential claims and defenses, as well as facts that would bear on the amount, type, and valuation of vegetation loss, potential reforestation, habitat loss, and other resources damaged or destroyed by the 2021 Dixie fire. PG&E Corporation and the Utility believe, however, that such losses could be significant with respect to fire suppression costs due to the size and duration of the 2021 Dixie fire and corresponding magnitude of fire suppression resources dedicated to fighting the 2021 Dixie fire and with respect to claims for damage to land and vegetation in national parks or national forests due to the very large number of acres of national park and national forests that were affected by the 2021 Dixie fire. According to the National Interagency Coordination Center Incident Management Situation Report dated October 29, 2021 at 7:30 a.m. Mountain Time, over $630 million of costs had been incurred in suppressing the 2021 Dixie fire. The Utility currently estimates that the fire burned approximately 70,000 acres of national parks and approximately 685,000 acres of national forests.

The Utility has liability insurance coverage for third-party liability attributable to periods in which both the 2020 Zogg fire and 2021 Dixie fire occurred in an aggregate amount of $900 million. Recovery under the Utility's insurance policies for the 2020 Zogg fire will reduce the amount of insurance proceeds available for the 2021 Dixie fire by the same amount. An immaterial decrease was recorded in the fourth quarter of 2021. As of December 31, 2021, the Utility has recorded an insurance receivable of $563 million for probable insurance recoveries in connection with the 2021 Dixie fire, which equals the aggregate $900 million of available insurance coverage for third-party liability attributable to the 2021 Dixie fire, less the $337 million insurance receivable recorded in connection with the 2020 Zogg fire.

As of December 31, 2021, the Utility has recorded a Wildfire Fund receivable of $150 million for probable recoveries in connection with the 2021 Dixie fire. See "Wildfire Fund under AB 1054" below. The Utility has also recorded a $101 million reduction to its regulatory liability for wildfire-related claims costs that were determined to be probable of recovery through the FERC TO formula rate and a $347 million regulatory asset for costs that were determined to be probable of recovery through the WEMA. See "Regulatory Recovery" below. Decreases in the amount of the insurance receivable for the 2021 Dixie fire may also increase the amount that is probable of recovery through the FERC TO formula rate and the WEMA. An immaterial increase was recorded in the fourth quarter of 2021.

Loss Recoveries

PG&E Corporation and the Utility have recovery mechanisms available for wildfire liabilities including from insurance, customers, and the Wildfire Fund. PG&E Corporation and the Utility record a receivable for a recovery when it is deemed probable that recovery of a recorded loss will occur, and the Utility can reasonably estimate the amount or its range. 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.

Total probable recoveries for the 2021 Dixie fire as of December 31, 2021 are:

Potential Recovery Source (in millions)	2021 Dixie fire
Insurance	$ 563
FERC TO rates	101
WEMA	347
Wildfire Fund	150
Probable recoveries at December 31, 2021	**$ 1,161**

The Utility could be subject to significant liability in connection with these wildfire events. If such liability is not recoverable from insurance or the other mechanisms described herein, it could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Insurance

Insurance Coverage

In April 2021, the Utility purchased approximately $268 million in wildfire liability insurance coverage for the period from April 13, 2021 to April 1, 2022, and approximately $32 million in incremental wildfire liability reinsurance for the period from April 1, 2021 to April 1, 2022 at a cost of approximately $220 million. This coverage is in addition to approximately $11 million in existing wildfire liability reinsurance for the period from July 1, 2020 to July 1, 2021 and approximately $600 million in existing wildfire liability insurance purchased by the Utility in August 2020 for the period from August 1, 2020 to August 1, 2021. On August 1, 2021, the $600 million of existing wildfire liability coverage renewed on a 12-month term covering the period from August 1, 2021 to August 1, 2022 at a cost of approximately $516 million pursuant to multi-year policy terms. The Utility's wildfire liability insurance is subject to an initial self-insured retention of $60 million.

In June 2021, the Utility purchased approximately $535 million in non-wildfire liability coverage for the period from June 1, 2021 to April 1, 2022 at a cost of approximately $89 million. This coverage is in addition to approximately $140 million in existing non-wildfire liability insurance for the period from August 1, 2020 to August 1, 2021. In connection with the June 2021 renewal, the Utility procured an extension of this existing coverage to April 1, 2022 at a premium cost of approximately $30 million. The Utility also has $50 million in additional non-wildfire liability coverage available through one of its wildfire liability policies with shared limits. The Utility's non-wildfire liability insurance is subject to an initial self-insured retention of $10 million. As of December 31, 2021, PG&E Corporation and the Utility had prepaid insurance of $358 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. For more information about the RTBA, see Note 4 above.

Insurance Receivable

Through December 31, 2021, PG&E Corporation and the Utility recorded $430 million for probable insurance recoveries in connection with the 2019 Kincade fire, $337 million for probable insurance recoveries in connection with the 2020 Zogg fire, and $563 million for probable insurance recoveries in connection with the 2021 Dixie fire. PG&E Corporation and the Utility intend to seek full recovery for all insured losses.

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)	**2021 Dixie fire**	**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**
Accrued insurance recoveries [1]	563	118	—	—	—	—	681
Reimbursements [2]	—	(67)	(16)	—	(25)	—	(108)
Balance at December 31, 2021	**$ 563**	**$ 270**	**$ 414**	**$ —**	**$ —**	**$ —**	**$ 1,247**

[1] During the fourth quarter of 2021, the accrued insurance recoveries decreased for the 2021 Dixie fire with a corresponding increase for the 2020 Zogg fire for $6.5 million.

[2] On January 26, 2022, the Utility received $43 million of insurance reimbursements related to the 2020 Zogg fire.

Regulatory Recovery

FERC TO rates

The Utility recognizes income and reduces its regulatory liability for potential refund through the FERC TO formula rate in future rates for a portion of the third-party wildfire-related claims in excess of insurance coverage. The allocation to transmission customers was based on a FERC-approved allocation factor as determined in the formula rate. Based on information currently available to the Utility regarding the 2021 Dixie fire, for the year ended December 31, 2021, the Utility recorded a $101 million reduction to its regulatory liability for wildfire-related claims costs that were determined to be probable of recovery through the FERC TO formula rate.

WEMA

In June 2018, the CPUC approved the establishment of the WEMA, which provides for tracking of incremental wildfire claims and outside legal costs plus incremental insurance premium costs above what is being recovered through rates. For the year ended December 31, 2021, based on information currently available to the Utility, incremental wildfire claims-related costs for the 2021 Dixie fire were determined to be probable of recovery and the Utility recorded a $347 million regulatory asset in the WEMA.

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. Each of California's large electric IOUs has elected to participate in the Wildfire Fund. 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 Coverage 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. The accrued Wildfire Fund receivable as of December 31, 2021 reflects an expectation that the Coverage Year will be based on the calendar year with coverage limited to the 2021 Dixie Fire. For 2022, PG&E Corporation and the Utility have elected a Coverage Year that commences on January 1, 2022 at 12:01 a.m. Pacific Time and ends on December 31, 2022 at 12:00 a.m. Pacific Time.

Electric utility companies that draw from the Wildfire Fund will only be required to reimburse amounts that are determined by the CPUC in a proceeding for cost recovery applying the prudency standard in AB 1054, not to be just and reasonable, subject to a disallowance cap equal to 20% of the IOU's transmission and distribution equity rate base. For the Utility, the disallowance cap would be approximately $2.9 billion based on its 2021 equity rate base, and is subject to adjustment based on changes in the Utility's total transmission and distribution equity rate base and would apply for a three calendar year period. 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 in accordance with the prudency standard in AB 1054 will not be reimbursed to the Wildfire Fund, resulting in a draw-down of the Wildfire Fund. The Utility expects that the same prudency standard would also be applied in any CPUC review of an application filed by the Utility seeking recovery of costs recorded to the WEMA.

Before the expiration of any current safety certification, the Utility must request a new safety certification from the OEIS, which the Utility expects to 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. An issued 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 14, 2021, the OEIS (then the Wildfire Safety Division of the CPUC) 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. On January 31, 2022, the OEIS approved the Utility's 2021 application and issued the Utility's 2021 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 customers, (ii) $7.5 billion in initial contributions from California's three large electric IOUs and (iii) $300 million in annual contributions paid by California's three large electric IOUs for a 10-year period. For more information see "Initial and Annual Contributions to the Wildfire Fund Established Pursuant to AB 1054" in Note 3 above.

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. The Wildfire Fund is available to pay for the Utility's eligible claims arising as of July 12, 2019, the effective date of AB 1054, subject to a limit of 40% of the allowed 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.

As of December 31, 2021, PG&E Corporation and the Utility recorded $150 million in Other noncurrent assets for Wildfire Fund receivables related to the 2021 Dixie fire.

For more information see Note 3 above.

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 then-current and former members of the boards of directors and certain then-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 denominated *In Re California North Bay Fire Derivative Litigation* (now re-captioned *Trotter v. Williams et al.*). 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 related to the 2017 Northern California wildfires 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. PG&E Corporation's and the Utility's rights with respect to PG&E Corporation's and the Utility's claims directly or indirectly related to any of the Fires (as defined in the Plan) against former officers and directors of PG&E Corporation and the Utility were assigned to the Fire Victim Trust under the Plan. 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 or the Utility for amounts paid pursuant to their indemnification obligations in connection with such causes of action. The assignment became effective as of the Emergence Date. On November 12, 2020, the trustee for the Fire Victim Trust filed a motion to intervene to substitute as the plaintiff in the matter, to which the parties later stipulated. On March 8, 2021, the court granted the parties' stipulation to substitute the trustee for the Fire Victim Trust as the plaintiff.

On December 24, 2018, a separate 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 then-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 trustee for the Fire Victim Trust as the plaintiff.

On February 24, 2021, the trustee filed an amended complaint in the *Trotter v. Chew* action, asserting two claims for breach of fiduciary duty against certain of PG&E Corporation's and the Utility's former directors and officers. Neither PG&E Corporation nor the Utility is a party to the action. On March 30, 2021, the *Trotter v. Chew* and *Trotter v. Williams* actions were consolidated. On April 26, 2021, the defendants filed demurrers to the amended complaint. On November 8, 2021, the Court entered an order sustaining in part and overruling in part the demurrers. On November 18, 2021, the trustee filed a second amended complaint. On December 21, 2021, the defendants filed demurrers to the second amended complaint. Trial is set for June 27, 2022.

On January 25, 2019, a separate 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 then-current and former officers and directors, and naming PG&E Corporation and the Utility as nominal defendants. A stipulation and proposed order to voluntarily dismiss this action was filed on April 20, 2021 and a case management conference on the dismissal order is set for March 9, 2022.

The above purported derivative lawsuits were brought against the named defendants on behalf of PG&E Corporation 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 or the Utility for amounts paid pursuant to their indemnification obligations in connection with such causes of action.

Securities Class Action Litigation

Wildfire-Related Securities Class Action

In June 2018, two purported securities class actions were filed in the United States District Court for the Northern District of California (the "District Court"), naming PG&E Corporation and certain of its then-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 Exchange Act 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,* U.S. District Court for the Northern District of California, Case No. 18-03509. The court also appointed PERA as lead plaintiff. PERA filed a consolidated amended complaint on November 9, 2018. On December 14, 2018, PERA filed a second amended consolidated complaint to add allegations regarding the 2018 Camp fire.

Due to the commencement of the Chapter 11 Cases, the proceedings were automatically stayed as to PG&E Corporation and the Utility.

On February 22, 2019, a third purported securities class action was filed in the District Court, 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 then-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 former 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 under submission with the District Court. The securities actions have been enjoined as to PG&E Corporation and the Utility pursuant to the Plan with any such claims submitted through a proof of claim to be resolved by the Bankruptcy Court as part of the claims reconciliation process in the Chapter 11 Cases. On April 29, 2021, the District Court issued a notice of intent to stay this action pending completion of the claims procedures in the bankruptcy proceedings. PERA filed objections to the notice of intent to stay on May 28, 2021. PG&E Corporation and the Utility filed a response to PERA's objections on June 10, 2021, the officer, director, and underwriter defendants filed a response to PERA's objections on June 11, 2021, and PERA filed a sur-response on June 21, 2021. The District Court has not taken further action with respect to its notice of intent to stay.

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 with respect to 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 any such allowed 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, 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 Emergence 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 Emergence 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, 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 financial condition, results of operations, liquidity, 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 Emergence 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. PERA has filed two motions seeking approval from the Bankruptcy Court to treat its proof of claim as a class claim. On February 27, 2020 and January 26, 2021, the Bankruptcy Court issued orders denying the motions. PERA filed an appeal of the February 27, 2020 order and on March 8, 2021, the District Court issued an order dismissing the appeal.

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 August 10, 2021, the District Court issued an order affirming the Bankruptcy Court's ruling with respect to the Insurance Deduction. On September 9, 2021, PERA filed a notice of appeal of the District Court's order to the Ninth Circuit Court of Appeals and on December 15, 2021, PERA filed its opening brief. PERA's appeal to the Ninth Circuit remains pending.

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 help facilitate the resolution of the Subordinated Claims. The motion, among other things, requested approval of procedures which would allow PG&E Corporation and the Utility to collect trading information with respect to the Subordinated Claims, to engage in an alternative dispute resolution process for resolving disputed Subordinated Claims, and to file certain 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 January 25, 2021, the Bankruptcy Court granted the Securities Claims Procedures Motion.

PG&E Corporation and the Utility have been working to resolve the Subordinated Claims in accordance with the procedures approved by the Bankruptcy Court, including by requesting trading information from holders of Subordinated Claims. Also, pursuant to those procedures, PG&E Corporation and the Utility have filed numerous omnibus objections in the Bankruptcy Court to certain of the Subordinated Claims. The Bankruptcy Court has entered several orders disallowing and expunging Subordinated Claims that were subject to these omnibus objections, and certain Subordinated Claims subject to these omnibus objections remain pending. PG&E Corporation and the Utility expect to file additional omnibus objections with respect to certain of the Subordinated Claims and to continue to act under the procedures approved by the Bankruptcy Court to resolve the Subordinated Claims.

Based on discussions with certain holders of the HoldCo Rescission or Damage Claims, PG&E Corporation believes it is probable that it will incur a loss in connection with the HoldCo Rescission or Damage Claims. As of the date of this filing, PG&E Corporation determined that the amount or range of such loss is not reasonably estimable because either a negotiated resolution would be contingent upon available insurance coverage, the scope of which has not yet been agreed, or any negotiated resolutions would be limited to a subset of immaterial claims. PG&E Corporation is further unable to estimate the amount or range of loss because the nature and value of HoldCo Rescission or Damage Claims varies significantly among potential claimholders, and as of the date of this filing, PG&E Corporation has only engaged in substantive discussions with a limited subset of claimholders.

PG&E Corporation and the Utility continue to believe it is reasonably possible that they will incur a loss in connection with the Subordinated Debt Claims but are unable to reasonably estimate the amount or range of loss because the nature and value, if any, of such claims varies significantly among potential claimholders. As of December 31, 2021, PG&E Corporation and the Utility have not recorded a liability in connection with the Subordinated Claims.

De-energization Securities 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 then-current director and certain then-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 PSPS events, 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 Exchange Act and Rule 10b-5 promulgated thereunder, and sought unspecified monetary relief, attorneys' fees and other costs.

On April 17, 2020, the plaintiffs filed an amended complaint asserting the same claims. The amended complaint added PG&E Corporation and a current officer of PG&E Corporation as defendants, and removed claims against certain current and former officers of PG&E Corporation previously named in the action.

On February 16, 2021, the plaintiffs filed a motion with the District Court for preliminary approval of a proposed settlement. On November 2, 2021, the District Court entered an order granting final approval of the settlement, which is now effective. Pursuant to the settlement stipulation: (1) PG&E Corporation paid $10 million, and (2) plaintiffs and the Settlement Class (as defined in the stipulation of settlement) released the Released Persons (as defined in 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 stipulation of settlement.

Indemnification Obligations and Directors' and Officers' Insurance Coverage

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 certain directors and officers in the securities class actions and in the litigation matters enumerated above under the heading "Wildfire-Related Derivative Litigation." 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 litigation matters enumerated above under the headings "Wildfire-Related Securities Class Action" and "Wildfire-Related Derivative Litigation," and are in arbitration with the carriers regarding, among other things, the applicability of multiple years of directors' and officers' insurance policies to those matters. Recovery under the directors' and officers' insurance policies in one such litigation matter will impact the directors' and officers' insurance proceeds available in the other matters.

On March 17, 2021, the trustee for the Fire Victim Trust filed a lawsuit entitled *Trotter v. PG&E Corporation, et al.*, in San Francisco Superior Court, seeking, among other things, a declaration that the trustee for the Fire Victim Trust be permitted to participate in the arbitration with the carriers. The trustee named PG&E Corporation, the Utility, and the insurance carriers as defendants. On March 25, 2021, PG&E Corporation and the Utility removed the action to the Bankruptcy Court. On March 29, 2021, the Fire Victim Trust filed a motion to remand the lawsuit back to state court, which the Bankruptcy Court denied on April 20, 2021. On April 30, 2021, the Fire Victim Trust moved for summary judgment. Oppositions and cross-motions to the summary judgment motion were filed by PG&E Corporation, the Utility and the insurance carriers on May 21, 2021. On June 22, 2021, the Bankruptcy Court entered an order denying the Fire Victim Trust's motion for summary judgment and granting the defendants' cross-motions for summary judgment. On June 29, 2021, the Bankruptcy Court entered judgment in favor of all defendants and against the Fire Victim Trust.

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, among other things.

The extent of PG&E Corporation's and the Utility's recovery of the directors' and officers' insurance proceeds could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

Butte County District Attorney's Office Investigation into the 2018 Camp Fire

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.

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 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 pleaded 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).

On August 20, 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. The Court continued the hearing to February 25, 2022.

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) $5.40 billion in cash that was contributed on the Emergence Date, (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 that was paid in cash on January 18, 2022, in each case pursuant to the terms of the tax benefits payment agreement between the Fire Victim Trust and the Utility, and (c) an amount of common stock representing 22.19% of the outstanding shares of PG&E Corporation on the Emergence Date, subject to potential adjustments.

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 and the Utility 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 had the ability to impose additional probation conditions on the Utility. On January 25, 2022, the period of probation expired.

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, Commission General Orders 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 Office of the Safety Advocate, and the Coalition of California Utility Employees jointly submitted to the CPUC a proposed settlement agreement in connection with this proceeding and jointly moved for its approval. The settlement agreement became effective on the Emergence Date.

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 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 recorded $1.625 billion of the disallowed costs for the year ended 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 and the amount of disallowance can be reasonably estimated.

The Utility expects additional system enhancement spending pursuant to the settlement agreement to 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 (iv) limits the tax savings that must be returned to customers 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. The CPUC approved the decision different on May 7, 2020.

As it relates to the additional $198 million in disallowed costs as adopted in the decision different, the Utility has recorded the full amount, primarily in the WMPMA through December 31, 2021.

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 the TO rate case for 2017 ("TO18"), the TO rate case for 2018 ("TO19"), and the TO rate case for 2019 ("TO20"), respectively.

On October 15, 2020, the FERC issued an order that, among other things, rejected 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. The order reopened the record for the limited purpose of allowing the parties an opportunity to present written evidence concerning the FERC's revised ROE methodology adopted in FERC Opinion No. 569-A, issued on May 21, 2020.

On December 17, 2020 and June 17, 2021, the FERC issued orders denying requests for rehearing submitted by the Utility and intervenors. In 2021, the Utility filed four appeals. The appeals related to two issues: (i) impact of the Tax Act on TO18 rates in January and February 2018 and (ii) aspects of the rehearing order other than the Tax Act. The appeals have been consolidated and are currently being held in abeyance until the FERC addresses the ROE issue.

As a result of an order denying rehearing on the common plant allocation, the Utility increased its Regulatory liabilities for amounts previously collected during the TO18, TO19, and TO20 rate case periods from 2017 through the fourth quarter of 2021 by approximately $324 million. A portion of these common plant costs are expected to be recovered at the CPUC in a separate application and as a result, the Utility has recorded approximately $197 million to Regulatory assets.

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 the TO18 proceeding.

On December 30, 2020, the FERC approved an all-party settlement agreement in connection with TO20. The TO20 settlement resolved all issues of the Utility's formula rate. However, some of the formula rate issues are contingent on the outcome of TO18, including the allocation of costs related to common, general and intangible plant. The settlement provides that the formula rate will remain in effect through December 31, 2023. The TO20 rate case provides that the transmission revenue requirement and rates are to be updated annually on January 1, subject to true-up. The Utility is required to make a successor rate filing in 2023, which would go into effect on January 1, 2024.

2018 CEMA Interim Rate Relief Subject to Refund

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with seven catastrophic events that included fire and storm declared emergencies from mid-2016 through early 2017, as well as $405 million related to work performed in 2016 and 2017 to cut back or remove dead or dying trees that were exposed to years of drought conditions and bark beetle infestation. The Utility filed three revisions to this application, resulting in a total cost recovery request of $763 million.

On April 25, 2019, the CPUC approved the Utility's request for interim rate relief, allowing for recovery of $373 million of costs as requested by the Utility at that time. The interim rate relief was implemented commencing on October 1, 2019. Costs included in the interim rate relief are subject to audit and refund.

On November 2, 2021, the Utility filed a settlement agreement with the active parties in the matter. The settlement agreement, if approved by the CPUC, would authorize the Utility to collect a total of $683 million plus interest for the 2018 CEMA application. As noted above, $373 million of the total amount has already been collected in interim rates. The interim rates would become final and no longer subject to refund. The remainder of the authorized revenue requirement that has yet to be collected would be amortized over a 12-month period.

2020 WMCE Interim Rate Relief Subject to Refund

On September 30, 2020, the Utility filed an application with the CPUC requesting cost recovery of recorded expenditures related to wildfire mitigation, certain catastrophic events, and a number of other activities (the "2020 WMCE application"). The recorded expenditures, which exclude amounts disallowed as a result of the CPUC's decision in the OII into the 2017 Northern California wildfires and the 2018 Camp fire, consist of $1.18 billion in expense and $801 million in capital expenditures, resulting in a proposed revenue requirement of approximately $1.28 billion.

As previously disclosed, on October 23, 2020, the CPUC approved $447 million in interim rate relief (which includes interest) pertaining to costs addressed in the 2020 WMCE application. All of the costs presented in the 2020 WMCE application are subject to the CPUC's reasonableness review, which could result in some or all of the interim rate relief of $447 million being subject to refund.

The costs addressed in the 2020 WMCE application cover activities mainly during the years 2017 to 2019 and are incremental to those previously authorized in the Utility's 2017 GRC and other proceedings. The majority of costs addressed in this application reflect work necessary to mitigate wildfire risk and to respond to catastrophic events occurring during the years 2017 to 2019. The Utility's requested revenue includes amounts for the FHPMA of $293 million, the FRMMA and the WMPMA of $740 million, and the CEMA of $251 million.

On September 21, 2021, the Utility filed a motion with the CPUC seeking approval of a settlement agreement that would authorize the Utility to continue to recover an interim revenue requirement of $447 million over a 17-month amortization period, followed by an additional revenue requirement of $591 million over a 24-month amortization period. On September 23, 2021, the CPUC extended the statutory deadline for a PD in this hearing to April 1, 2022.

2015 Gas Transmission and Storage Rate Case and 2011-2014 Gas Transmission and Storage Capital Expenditures Audit

In its final decision in the Utility's 2015 GT&S rate case, the CPUC excluded from rate base $696 million of capital spending in 2011 through 2014. This was the amount forecast to be recorded in excess of the amount adopted in the 2011 GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The audit report was released June 2, 2020 and did not recommend any additional disallowances. The 2015 GT&S decision authorized the Utility to seek recovery, through a separate application, of those costs not recommended for disallowance by the audit.

On July 31, 2020, the Utility filed an application seeking recovery of $416.3 million in 2015 to 2022 revenue associated with $512 million of recorded capital expenditures. On July 7, 2021, the Utility filed a joint motion to adopt a settlement agreement reached with the active parties in the proceeding. If approved by the CPUC, the settlement agreement would resolve all issues in this proceeding and would authorize a $356.3 million revenue requirement for the period of 2015 through 2022. Of this amount, $313.3 million of revenues for the period 2015 through 2021 would be amortized in rates over 60 months and $43 million associated with 2022 would be amortized in rates over 12 months through an annual gas true-up filing for rates effective January 1, 2022. Going forward, the as-yet undepreciated capital plant associated with this application would be included in test year 2023 rate base in the Utility's consolidated 2023 GRC. No party submitted comments on the settlement.

The Utility is unable to determine the timing and outcome of this 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 $77 million and $144 million as of December 31, 2021 and December 31, 2020, respectively. These amounts were included in Other current liabilities on the Consolidated Financial Statements. 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. On March 30, 2020, the Bankruptcy Court granted the Utility's motion to dismiss this class action because the plaintiff's class action claims are preempted as a matter of law by the California Public Utilities Code. On April 3, 2020, the Bankruptcy Court entered an order dismissing the action without leave to amend.

The plaintiff appealed the decision dismissing the complaint to the District Court. On March 26, 2021, the District Court affirmed the Bankruptcy Court's dismissal of this action, and the plaintiff filed a notice of appeal to the Ninth Circuit Court of Appeals. The appellant filed its opening brief on June 25, 2021. A former executive director of the CPUC filed an amicus brief on July 2, 2021, asking the Ninth Circuit Court of Appeals to reverse the decision of the District Court and to remand the case for further proceedings. The answering brief of PG&E Corporation and the Utility was filed August 25, 2021. On September 1, 2021, the CPUC filed an amicus brief asking the Ninth Circuit Court of Appeals to affirm the District Court's dismissal. The appellant's reply brief was filed on October 15, 2021. A panel of the Ninth Circuit Court of Appeals heard oral argument on the plaintiff's appeal on January 12, 2022.

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

CZU Lightning Complex Fire Notices of Violation

Between November 2020 and January 2021, several governmental entities raised concerns regarding the Utility's emergency response to the 2020 CZU Lightning Complex fire, including Cal Fire, the California Coastal Commission, the Central Coast Regional Water Quality Control Board, and Santa Cruz County Board of Supervisors alleging environmental, vegetation management, and unpermitted work violations. In the matter of Santa Cruz County's complaint with the CPUC, the parties reached a settlement, and the CPUC dismissed the complaint on December 15, 2021. The Utility continues to work with the California Coastal Commission, Cal Fire, and the Central Coast Regional Water Quality Control Board to resolve any outstanding issues and to work with Santa Cruz County to implement the terms of the settlement agreement.

Based on the information currently available, PG&E Corporation and the Utility believe it is probable that a liability has been incurred. Accordingly, PG&E Corporation and the Utility recorded a charge during the fourth quarter ended December 31, 2021 for an amount that is not material. 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:

	Balance at	
(in millions)	**December 31, 2021**	**December 31, 2020**
Topock natural gas compressor station	$ 299	$ 303
Hinkley natural gas compressor station	123	132
Former MGP sites owned by the Utility or third parties [(1)]	667	659
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites [(2)]	104	111
Fossil fuel-fired generation facilities and sites [(3)]	70	96
Total environmental remediation liability	**$ 1,263**	**$ 1,301**

(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 MGP 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 as of December 31, 2021, 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. As of December 31, 2021, the Utility expected to recover $982 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 $220 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 through 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 2022. 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 $477 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 through 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 $50 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 through 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. EMANI shares losses with NEIL as part of the first $400 million in coverage for nuclear or non-nuclear property damages. Additional coverage is procured through 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. The excess insurance coverage through 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 $42 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 $13.6 billion. The Utility purchases the maximum available public liability insurance of $450 million for Diablo Canyon. The balance of the $13.6 billion of liability protection is provided under a loss-sharing program among nuclear reactor owners. 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 experienced five outages between July 2020 and April 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 occurred 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. During July 2020 through April 2021, the Utility implemented effective corrective actions. The Utility continues to monitor the affected component.

If additional shutdowns occur in the future, 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 in the 2021 Energy Resource Recovery Account compliance proceeding.

PG&E Corporation and the Utility do not currently believe that the resolution of this matter will have a material impact on their financial condition, results of operations, or cash flows.

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, 2021:

	Power Purchase Agreements					
(in millions)	**Renewable Energy**	**Conventional Energy**	**Other**	**Natural Gas**	**Nuclear Fuel**	**Total**
2022	$ 2,062	$ 530	$ 61	$ 823	$ 42	$ 3,518
2023	2,043	425	61	191	41	2,761
2024	2,020	282	61	157	27	2,547
2025	2,009	216	61	157	—	2,443
2026	1,948	204	21	140	—	2,313
Thereafter	19,310	539	19	52	—	19,920
Total purchase commitments	**$ 29,392**	**$ 2,196**	**$ 284**	**$ 1,520**	**$ 110**	**$ 33,502**

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, 2021, renewable energy contracts expire at various dates between 2022 and 2041.

Conventional Energy Power Purchase Agreements. The Utility has entered into many power purchase agreements for conventional generation resources, which include tolling agreements and RA agreements. The Utility's obligations under a portion of these agreements are contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. These power purchase agreements expire at various dates between 2022 and 2041.

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, 2021, QF contracts in operation expire at various dates between 2022 and 2041. 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 $3.0 billion in 2021, $2.9 billion in 2020, and $3.0 billion in 2019.

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 2022 and 2041. 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 $1.2 billion in 2021, $0.8 billion in 2020, and $0.9 billion in 2019.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2022 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 $79 million in 2021, $111 million in 2020, and $74 million in 2019.

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 2022 and 2052. At December 31, 2021, the future minimum payments related to these commitments were as follows:

(in millions)	**Other Commitments**
2022	$ 43
2023	65
2024	81
2025	77
2026	74
Thereafter	2,938
Total minimum lease payments	**$ 3,278**

Payments for other commitments amounted to $50 million in 2021, $45 million in 2020, and $48 million in 2019. 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.

Oakland Headquarters Lease

On October 23, 2020, the Utility and BA2 300 Lakeside LLC ("Landlord"), a wholly-owned subsidiary of TMG Bay Area Investments II, LLC, entered into an office lease agreement for approximately 910,000 rentable square feet of space within the Lakeside Building to serve as the Utility's principal administrative headquarters (the "Lease"). In connection with the Lease, the Utility also 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 April 8, 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.

As space in the Lakeside Building becomes available following the expiration of existing tenants' leases and completion of the redevelopment of the property to the Utility's specifications, the Utility expects to relocate employees and operations from the SFGO and certain East Bay office locations to the Lakeside Building in phases over several years, beginning in 2022.

At December 31, 2021, the Lease had no impact on PG&E Corporation's and the Utility's Consolidated Financial Statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and the Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2021, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2021.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of PG&E Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, equity and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America (GAAP).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 10, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulation and Regulated Operations—Refer to Notes 3, 4 and 14 to the financial statements

Critical Audit Matter Description

The Company's subsidiary, Pacific Gas & Electric Company, follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the California Public Utilities Commission ("CPUC") or the Federal Energy Regulatory Commission based on its cost of providing service. Pacific Gas & Electric Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. Pacific Gas & Electric Company 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.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the likelihood of recovery of incurred costs in current or future rates due in part to the uncertainty related to future decisions by the rate regulators. This required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and a high degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions that the costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset under GAAP and are recorded at the appropriate amount.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of specialized rules to account for the effects of cost-based rate regulation related to the uncertainty of future decisions by the rate regulators and the costs approved by a CPUC decision for tracking purposes that meet the definition of a regulatory asset and are recorded at the appropriate amount included the following, among others:

- We tested the effectiveness of controls over (1) the evaluation of the likelihood of (a) the recovery in future rates of costs deferred as regulatory assets and (b) regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; (2) management's determination that costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset and are recorded at the appropriate amount; and (3) the review of disclosures related to these matters.

- We read relevant regulatory orders issued by the CPUC for Pacific Gas and Electric Company and other public utilities in California, procedural filings, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates based on precedents of the CPUC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset balances for completeness.

- For regulatory matters in process (e.g., applications for cost recovery), we inspected Pacific Gas and Electric Company's filings with the CPUC and the filings with the CPUC by intervenors that may affected Pacific Gas and Electric Company's future rates, for any evidence that might contradict management's assertions.

- For regulatory assets approved by a CPUC decision for tracking purposes, we selected samples of costs and evaluated whether they met the definition of a regulatory asset by comparing the costs to the description of the costs approved by a CPUC decision and were recorded at the appropriate amount.

- We evaluated whether the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, were appropriate and consistent with the information obtained in our procedures.

Wildfire-Related Contingencies—Refer to Note 14 to the financial statements

Critical Audit Matter Description

The Company has recorded provisions for loss contingencies related to the 2019 Kincade fire, 2020 Zogg fire and 2021 Dixie fire. The Company has recorded an estimated probable loss of $2,325 million as of December 31, 2021, which represents the lower end of the range of reasonably possible losses in connection with the fires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because (1) of the significant judgments made by management to estimate losses and (2) the outcome of the wildfire-related contingencies materially affects the Company's financial position, results of operations, and cash flows. This required the application of a high degree of auditor judgment and extensive audit effort when performing audit procedures to evaluate the reasonableness of management's estimated losses and disclosure related to wildfire-related contingencies.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding its estimated losses for wildfire-related contingencies and related disclosures included the following, among others:

- We tested the effectiveness of controls over (1) the Company's determination of whether a loss was probable or reasonably possible; (2) the determination of the significant assumptions, including the information gained through investigations into the cause of the fire, information from claimants, and the advice of legal counsel that may affect the valuation of the liability; and (3) the disclosures related to the wildfires.

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the wildfires by inquiring of management and the Company's legal counsel regarding the amounts of probable and reasonably possible losses, including the potential impact of information gained through investigations into the cause of the fires, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.

- We evaluated the estimation methodology for determining the amount of probable loss through inquiries with management; we tested the significant assumptions used in the valuation of the liability. With the assistance of our real estate valuation specialists, we assessed the appropriateness of the data sources utilized to determine the assumption utilized in management's estimate.

- We read the legal letters from the Company's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.

- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

Sale of Transmission Tower Wireless Licenses Agreement—Refer to Notes 3 and 4 to the financial statements

Critical Audit Matter Description

The Company's subsidiary, Pacific Gas & Electric Company, granted an exclusive license to a third party to sublicense and market wireless communications equipment attachment locations on the Utility's structures and to add additional cell sites to the license. The Utility received $947 million in proceeds, and recorded $370 million as a financing obligation, $106 million as a contract liability (deferred revenue), and $471 million as regulatory liabilities.

We identified the accounting for the sale of the wireless licenses as a critical audit matter due to the significant judgments made by management in the application of accounting guidance. This required specialized knowledge of accounting for the sale of future revenue and leases as well as rate regulation due to its inherent complexities and extensive audit effort when performing audit procedures to evaluate the accounting treatment associated with the transaction.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of accounting guidance for the Sale of Transmission Tower Wireless Licenses Agreement included the following:

- We tested the effectiveness of controls over the evaluation of the accounting treatment for the Sale of Transmission Tower Wireless Licenses Agreement.

- With the assistance of professionals in our firm having expertise in accounting for the sale of future revenue and leases, we evaluated the conclusions regarding the sale of future revenue, deferred revenue and regulatory liability accounting treatment applied to the Sale of Transmission Tower Wireless Licenses Agreement by performing the following:

    - Reading the contract terms and conditions included in the agreements

    - We read the Company's analysis of the appropriate accounting guidance

    - Evaluating the conclusions regarding the accounting guidance used to account for the transaction

- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 10, 2022

We have served as the Company's auditor since 1999.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Pacific Gas and Electric Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2021 and 2020, the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Utility as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America (GAAP).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Utility's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 10, 2022, expressed an unqualified opinion on the Utility's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Utility's management. Our responsibility is to express an opinion on the Utility's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulation and Regulated Operations – Refer to Notes 3, 4 and 14 to the financial statements

Critical Audit Matter Description

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the California Public Utilities Commission ("CPUC") or the Federal Energy Regulatory Commission based on its cost of providing service. 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. We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the likelihood of recovery of incurred costs in current or future rates due in part to the uncertainty related to future decisions by the rate regulators. This required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and a high degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions that the costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset under GAAP and are recorded at the appropriate amount.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of specialized rules to account for the effects of cost-based rate regulation related to the uncertainty of future decisions by the rate regulators and the costs approved by a CPUC decision for tracking purposes that meet the definition of a regulatory asset and are recorded at the appropriate amount included the following, among others:

- We tested the effectiveness of controls over (1) the evaluation of the likelihood of (a) the recovery in future rates of costs deferred as regulatory assets and (b) regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; (2) management's determination that costs approved by a CPUC decision for tracking purposes meet the definition of a regulatory asset and are recorded at the appropriate amount; and (3) the review of disclosures related to these matters.

- We read relevant regulatory orders issued by the CPUC for the Utility and other public utilities in California, procedural filings, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates based on precedents of the CPUC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset balances for completeness.

- For regulatory matters in process (e.g., applications for cost recovery), we inspected the Utility's filings with the CPUC and the filings with the CPUC by intervenors that may affect the Utility's future rates, for any evidence that might contradict management's assertions.

- For regulatory assets approved by a CPUC decision for tracking purposes, we selected samples of costs and evaluated whether they met the definition of a regulatory asset by comparing the costs to the description of the costs approved by a CPUC decision and were recorded at the appropriate amount.

- We evaluated whether the Utility's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments, were appropriate and consistent with the information obtained in our procedures.

Wildfire-Related Contingencies—Refer to Note 14 to the financial statements

Critical Audit Matter Description

The Utility has recorded provisions for loss contingencies related to the 2019 Kincade fire, 2020 Zogg fire and 2021 Dixie fire. The Utility has recorded an estimated probable loss of $2,325 million as of December 31, 2021, which represents the lower end of the range of reasonably possible losses in connection with the fires.

We identified wildfire-related contingencies and the related disclosures as a critical audit matter because (1) of the significant judgments made by management to estimate losses and (2) the outcome of the wildfire-related contingencies materially affects the Utility's financial position, results of operations, and cash flows. This required the application of a high degree of auditor judgment and extensive audit effort when performing audit procedures to evaluate the reasonableness of management's estimated losses and disclosure related to wildfire-related contingencies.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's judgments regarding its estimated losses for wildfire-related contingencies and related disclosures included the following, among others:

- We tested the effectiveness of controls over (1) the Utility's determination of whether a loss was probable or reasonably possible; (2) the determination of the significant assumptions, including the information gained through investigations into the cause of the fires, information from claimants, and the advice of legal counsel that may affect the valuation of the liability; and (3) the disclosures related to the wildfires.

- We evaluated management's judgments related to whether a loss was probable or reasonably possible for the wildfires by inquiring of management and the Utility's legal counsel regarding the amounts of probable and reasonably possible losses, including the potential impact of information gained through investigations into the cause of the fire, information from claimants, the advice of legal counsel, and reading external information for any evidence that might contradict management's assertions.

- We evaluated the estimation methodology for determining the amount of probable loss through inquiries with management; we tested the significant assumptions used in the valuation of the liability. With the assistance of our real estate valuation specialists, we assessed the appropriateness the data sources utilized to determine the assumption utilized in management's estimate.

- We read the legal letters from the Utility's external and internal legal counsel regarding known information and evaluated whether the information therein was consistent with the information obtained in our procedures.

- We evaluated whether the Utility's disclosures were appropriate and consistent with the information obtained in our procedures.

Sale of Transmission Tower Wireless Licenses Agreement—Refer to Notes 3 and 4 to the financial statements

Critical Audit Matter Description

The Utility has granted an exclusive license to a third party to sublicense and market wireless communications equipment attachment locations on the Utility's structures and add additional cell sites to the license. The Utility received $947 million in proceeds, and recorded $370 million as a financing obligation, $106 million as a contract liability (deferred revenue), and $471 million as regulatory liabilities.

We identified the accounting for the sale of the wireless licenses as a critical audit matter due to the significant judgments made by management in the application of accounting guidance. This required specialized knowledge of accounting for the sale of future revenue and leases as well as rate regulation due to its inherent complexities and extensive audit effort when performing audit procedures to evaluate the accounting treatment associated with the transaction.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of accounting guidance for the Sale of Transmission Tower Wireless Licenses Agreement included the following:

- We tested the effectiveness of controls over the evaluation of the accounting treatment for the Sale of Transmission Tower Wireless Licenses Agreement.

- With the assistance of professionals in our firm having expertise in accounting for the sale of future revenue and leases, we evaluated the conclusions regarding the sale of future revenue, deferred revenue and regulatory liability accounting treatment applied to the Sale of Transmission Tower Wireless Licenses Agreement by performing the following:

    - Reading the contract terms and conditions included in the agreements

    - Evaluating the conclusions regarding the accounting guidance used to account for the transaction

- We evaluated whether the Company's disclosures were appropriate and consistent with the information obtained in our procedures.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 10, 2022

We have served as the Utility's auditor since 1999.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of PG&E Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated February 10, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 10, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Pacific Gas and Electric Company

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Utility and our report dated February 10, 2022, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Utility's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 10, 2022

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCE DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2021, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this 2021 Form 10-K under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

Registered Public Accounting Firm's Report on Internal Control over Financial Reporting

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Information About Our Executive Officers" at the end of Part I of this 2021 Form 10-K. Other information regarding directors will be included under the heading "Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

The following documents are available both on the Corporate Governance section of PG&E Corporation's website (*www.pgecorp.com/corp/about-us/corporate-governance.page*) and on the Utility's website (*www.pge.com/en_US/about-pge/company-information/company-information.page,* under the Corporate Governance and the Compliance & Ethics tabs): (1) PG&E Corporation's and the Utility's code of conduct (which meets the definition of "code of ethics" of Item 406(b) of the SEC Regulation S-K) adopted by PG&E Corporation and the Utility and applicable to their directors and employees, including their respective principal executive officers, principal financial officers, controllers, and other executive officers, (2) PG&E Corporation's and the Utility's respective corporate governance guidelines, and (3) key Board committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Sustainability and Governance Committee and the People and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the "code of ethics" by PG&E Corporation or the Utility and that apply to its respective principal executive officers, principal financial officers, or controllers, PG&E Corporation or the Utility, as appropriate, will post the amended code of ethics and any waivers at www.pgecorp.com/corp/about-us/compliance-ethics/program.page.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

There were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2021 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

Audit Committees and Audit Committee Financial Expert

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial experts" as defined by the SEC will be included under the heading "Committees and Memberships" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, will be included under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2021," "Grants of Plan-Based Awards in 2021," "Outstanding Equity Awards at Fiscal Year End - 2021," "Option Exercises and Stock Vested during 2021," "Pension Benefits - 2021," "Non-Qualified Deferred Compensation - 2021," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability," "Compensation of Non-Employee Directors," and "Principal Executive Officers' (PEO) Pay Ratio - 2021" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2021 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by shareholders	31,167,681 (1)	$ 40.05 (2)	58,552,721 (3)
Equity compensation plans not approved by shareholders	—	—	—
Total equity compensation plans	31,167,681 (1)	$ 40.05 (2)	58,552,721 (3)

(1) Includes 160 phantom stock units, 9,658,300 restricted stock units and 19,313,387 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares granted in 2021, reflects the estimated payout percentage of zero percent for performance shares using a total shareholder return and financial metric, 200% for performance shares using operational metrics. The actual number of shares issued can range from zero percent to 200% of target depending on achievement of performance objectives. For performance-based stock options, amounts reflected in this table reflect actual payout of 102%. Restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) This is the weighted average exercise price for the 2,195,834 options outstanding as of December 31, 2021.

(3) Represents the total number of shares available for issuance under all PG&E Corporation's equity compensation plans as of December 31, 2021. Stock-based awards granted under these plans include restricted stock units, performance shares, stock options, and phantom stock units. The LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the LTIP. In addition, 5.5 million shares related to awards outstanding under the 2006 long-term incentive plan at December 31, 2013, or awards granted under the 2006 long-term incentive plan from January 1, 2014, through May 11, 2014, were cancelled, forfeited or expired and became available for issuance under the LTIP. A further 30 million shares were authorized for issuance under the LTIP on July 1, 2020, as part of the Plan. Lastly, an additional 44 million shares were authorized for issuance under the new 2021 LTIP plan on June 1, 2021.

For more information, see Note 6 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information responding to Item 13, for each of PG&E Corporation and the Utility, will be included under the headings "Related Party Transactions," "Independence," and "Committees and Memberships" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to Item 14, for each of PG&E Corporation and the Utility, will be included under the heading "Information Regarding the Independent Auditor for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2022 Annual Meetings of Shareholders, which information is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a. The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2021, 2020, and 2019 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2021 and 2020 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2021, 2020, and 2019 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2021, 2020, and 2019 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Management's Report on Internal Controls.

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Condensed Financial Information of Parent as of December 31, 2021 and 2020 and for the Years Ended December 31, 2021, 2020, and 2019.

Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2021, 2020, and 2019.

3. Exhibits required by Item 601 of Regulation S-K

Exhibit Number	Exhibit Description
3.1	Amended and Restated Articles of Incorporation of PG&E Corporation, effective as of May 29, 2002, as amended by the Amendment dated June 22, 2020 (incorporated by reference to PG&E Corporation's Form 8 K dated June 20, 2020 (File No. 1-12609) Exhibit 3.1)
3.2	Bylaws of PG&E Corporation, Amended and Restated as of June 22, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated June 20, 2020 (File No. 1-12609) Exhibit 3.3)
3.3	Amended and Restated Articles of Incorporation of Pacific Gas and Electric Company, effective as of June 22, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 20, 2020 (File No. 1-2348), Exhibit 3.2)
3.4	Bylaws of Pacific Gas and Electric Company, Amended and Restated as of May 20, 2021 (incorporated by reference in Pacific Gas and Electric Company's Form 10-Q dated May 20, 2021 (File No. 1-2348), Exhibit 3.1)
3.5	Amended and Restated Limited Liability Company Agreement of PG&E Recovery Funding LLC, dated as of October 27, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 4, 2021 (File No. 1-2348), Exhibit 3.2)

4.1	Indenture, dated as of August 6, 2018, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture, dated as of August 6, 2018, relating to the issuance by Pacific Gas and Electric Company of $500,000,000 aggregate principal amount of 4.25% Senior Notes due August 1, 2023 and $300,000,000 aggregate principal amount of 4.65% Senior Notes due August 1, 2028 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.2)
4.3	Second Supplemental Indenture, dated as of July 1, 2020, to the Indenture, dated as of August 6, 2018, between Pacific Gas and Electric Company and BOKF, N.A., as trustee (including forms of certain series of Reinstated Senior Notes) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated July 2, 2020 (File No. 1-2348), Exhibit 4.5)
4.4	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1)
4.5	First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of $700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.6	Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of $400,000,000 of Pacific Gas and Electric Company's 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1)
4.7	Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)
4.8	Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1)
4.9	Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of $250,000,000 aggregate principal amount of its 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1)
4.10	Ninth Supplemental Indenture, dated as of June 3, 2021, relating to the $800,000,000 aggregate principal amount of 3.000% First Mortgage Bonds due June 15, 2028 (the "First Mortgage Bonds"), between Pacific Gas and Electric Company and the Trustee (including the form of First Mortgage Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 1-2348), Exhibit 4.1)
4.11	Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1)
4.12	Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)
4.13	Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)

4.14	Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
4.15	Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.16	Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.17	Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of $375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)
4.18	Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)
4.19	Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No. 1-2348), Exhibit 4.1)
4.20	Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1)
4.21	Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1)
4.22	Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1)
4.23	Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1)
4.24	Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1)
4.25	Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and $400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1)

4.26	Twenty-Ninth Supplemental Indenture, dated as of March 10, 2017, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.30% Senior Notes due March 15, 2027 and $200,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 10, 2017 (File No. 1-2348), Exhibit 4.1)
4.27	Thirtieth Supplemental Indenture, dated as of July 1, 2020, to the Amended and Restated Indenture, dated as of April 22, 2005, between Pacific Gas and Electric Company and BOKF, N.A., as trustee (including forms of certain series of Reinstated Senior Notes as defined therein) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.3)
4.28	Indenture, dated as of November 29, 2017, relating to the issuance of $500,000,000 aggregate principal amount of by Pacific Gas and Electric Company's Floating Rate Senior Notes due November 28, 2018, $1,150,000,000 aggregate principal amount of its 3.30% Senior Notes due December 1, 2027 and $850,000,000 aggregate principal amount of its 3.95% Senior Notes due December 1, 2047 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 4.1)
4.29	First Supplemental Indenture, dated as of July 1, 2020, to the Indenture, dated as of November 29, 2017, between Pacific Gas and Electric Company and BOKF, N.A., as trustee (including forms of certain series of Reinstated Senior Notes as defined therein) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.4)
4.30	Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 dated February 11, 2014 (File No. 333-193880), Exhibit 4.1)
4.31	Indenture of Mortgage, dated as of June 19, 2020, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 19, 2020 (File No. 1-2348), Exhibit 4.1)
4.32	First Supplemental Indenture, dated as of June 19, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the 1.75% First Mortgage Bonds due June 16, 2022, 2.10% First Mortgage Bonds due August 1, 2027, 2.50% First Mortgage Bonds due February 1, 2031, 3.30% First Mortgage Bonds due August 1, 2040 and 3.50% First Mortgage Bonds due August 1, 2050, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (including the form of Mortgage Bonds of each series) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 19, 2020 (File No. 1-2348), Exhibit 4.2)
4.33	Second Supplemental Indenture, dated as of July 1, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (including forms of the Senior Notes Collateral Bonds as defined therein) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.6)
4.34	Third Supplemental Indenture, dated as of July 1, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, relating to 3.75% First Mortgage Bond due July 1, 2028 and 3.45% First Mortgage Bond due July 1, 2025 (collectively, the "Short-Term Exchange Mortgage Bonds") and 4.95% First Mortgage Bond due July 1, 2050 and 4.55% First Mortgage Bond due July 1, 2030 (collectively, the "Long-Term Exchange Mortgage Bonds") between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (including forms of the Short-Term Exchange Mortgage Bonds and the Long-Term Exchange Mortgage Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.1)
4.35	Fourth Supplemental Indenture, dated as of July 1, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, relating to 3.15% First Mortgage Bond due July 1, 2026 and 4.50% First Mortgage Bond due July 1, 2040 (collectively, the "Funded Debt Mortgage Bonds") between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (including forms of the Funded Debt Mortgage Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.2)
4.36	Fifth Supplemental Indenture, dated as of July 1, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (including forms of the collateral bonds securing the $1,500,000,000 18-month term loan facility and the $1,500,000,000 364-day term loan facility) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.7)

4.37	Sixth Supplemental Indenture, dated as of August 1, 2020, to the Indenture of Mortgage, dated as of June 19, 2020, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 4.15)
4.38	Pledge Agreement, dated as of October 5, 2020, by and between Pacific Gas and Electric Company and MUFG Bank, Ltd. (incorporated by reference to PG&E Corporation's Form 8-K dated October 5, 2020 (File No. 1-12609), Exhibit 4.1)
4.39	Eighth Supplemental Indenture, dated as of March 11, 2021, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the $1,500,000,000 aggregate principal amount of 1.367% First Mortgage Bonds due March 10, 2023, $450,000,000 aggregate principal amount of 3.25% First Mortgage Bonds due June 1, 2031 Bonds and $450,000,000 aggregate principal amount of 4.20% First Mortgage Bonds due June 1, 2041 Bonds, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A.(including the form of First Mortgage Bonds of each series) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 8, 2021 (File No. 1-2348), Exhibit 4.1)
4.40	Ninth Supplemental Indenture, dated as of June 3, 2021, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the $800,000,000 aggregate principal amount of 3.000% First Mortgage Bonds due June 15, 2028 (the "2028 Bonds"), between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (including the form of 2028 Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 1-2348), Exhibit 4.1)
4.41	Tenth Supplemental Indenture, dated as of June 22, 2021, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the collateral bonds, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (including the forms of collateral bonds securing the revolving credit facility) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2021 (File No. 1-2348), Exhibit 4.1)
4.42	Eleventh Supplemental Indenture, dated as of October 29, 2021, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the collateral bond, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (including the form of collateral bond securing the 18-month term loan facility) (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-2348), Exhibit 4.2)
4.43	Twelfth Supplemental Indenture, dated as of November 15, 2021, to the Indenture of Mortgage, dated as of June 19, 2020, relating to the $300,000,000 aggregate principal amount of Floating Rate Mortgage Bonds due November 14, 2022 (the "Floating Rate Mortgage Bonds") and the $900,000,000 aggregate principal amount of 1.70% First Mortgage Bonds due November 15, 2023 (the "2023 Bonds"), between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A. (including the forms of Floating Rate Mortgage Bonds and 2023 Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 10, 2021 File No. 1-2348), Exhibit 4.1)
4.44	Indenture, dated as of June 23, 2020, between PG&E Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to PG&E Corporation's Form 8-K dated June 19, 2020 (File No. 1-12609), Exhibit 4.1)
4.45	First Supplemental Indenture, dated as of June 23, 2020, to the Indenture, dated as of June 23, 2020, relating to the 5.000% Senior Secured Notes due July 1, 2028 (the "2028 Notes") and the 5.250% Senior Secured Notes due July 1, 2030 (the "2030 Notes"; together with the 2028 Notes, the "Notes"), by and among PG&E Corporation, The Bank of New York Mellon Trust Company, N.A., and JP Morgan Chase Bank N.A., as collateral agent (including the form of Notes for each series) (incorporated by reference to PG&E Corporation's Form 8-K dated June 19, 2020 (File No. 1-2609), Exhibit 4.2)
4.46	Escrow Deposit and Disbursement Agreement, dated as of June 23, 2020, by and among PG&E Corporation, The Bank of New York Mellon Trust Company, N.A., as escrow agent (incorporated by reference to PG&E Corporation's Form 8-K dated June 19, 2020 (File No. 1-2609), Exhibit 4.3)
4.47	Calculation Agency Agreement, dated as June 19, 2020, by and between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A, as calculation agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 19, 2020 (File No. 1-2348), Exhibit 4.3)
4.48	Escrow Deposit and Disbursement Agreement, dated as of June 19, 2020, by and among Pacific Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A., as escrow agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 19, 2020 (File No. 1-2348), Exhibit 4.4)

4.49		Indenture, dated as of November 12, 2021, by and between PG&E Recovery Funding LLC and The Bank of New York Melon Trust Company, N.A. (including forms of the Senior Secured Recovery Bonds) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2021 (File No. 1-12609), Exhibit 4.1)
4.50		Series Supplement, dated as of November 12, 2021, by and between PG&E Recovery Funding LLC and The Bank of New York Melon Trust Company, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2021 (File No. 1-12609), Exhibit 4.2)
4.51(a)		Description of PG&E Corporation's Securities – Common Stock and Equity Units
4.51(b)		Description of Pacific Gas and Electric Company's Securities – Preferred Stock
10.1		Second Amended and Restated Credit Agreement, dated as of April 27, 2015, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank, National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1)
10.2		Second Amended and Restated Credit Agreement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC, as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association, as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-2348), Exhibit 10.2)
10.3		Term Loan Agreement, dated as of April 16, 2018, by and among PG&E Corporation, the several banks and other financial institutions or entities from time to time parties thereto, Mizuho Bank, Ltd., Royal Bank of Canada and Sumitomo Mitsui Banking Corporation, as joint lead arrangers and joint bookrunners and Mizuho Bank, Ltd., as administrative agent (incorporated by reference to PG&E Corporation's Form 8-K dated April 16, 2018 (File No. 1-12609), Exhibit 10.1)
10.4		Term Loan Agreement, dated as of February 23, 2018, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities from time to time parties thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and U.S. Bank National Association, as joint lead arrangers and joint bookrunners and The Bank of Tokyo-Mitsubishi UFJ, Ltd, as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 23, 2018 (File No. 1-02348), Exhibit 10.1)
10.5		Transmission Control Agreement among the California Independent System Operator Corporation (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.8)
10.6	*	Agreement to Enter Into Lease and Purchase Option, dated June 5, 2020, between Pacific Gas and Electric Company and TMG Bay Area Investments II, LLC (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 5, 2020 (File No. 1-2348), Exhibit 10.1)
10.7	*	Office Lease, dated as of October 23, 2020, by and between Pacific Gas and Electric Company and BA2 300 Lakeside LLC (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.12)
10.8		Calculation Agency Agreement, dated as of November 16, 2020, between Pacific Gas and Electric Company and The Bank of New York Mellon Trust Company, N.A, as calculation agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 16, 2020 (File No. 1-2348), Exhibit 4.2)

10.9	Repricing Amendment, dated February 1, 2021, by and among PG&E Corporation, the Consenting Lenders, the New Lenders (each as defined therein) and JPMorgan Chase Bank, N.A, as administrative agent (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.2)
10.10	Underwriting Agreement, dated March 8, 2021, by and among Pacific Gas and Electric Company, BNP Paribas Securities Corp., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and MUFG Securities Americas Inc. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 8, 2021 (File No. 1-2348), Exhibit 1.1)
10.11	Underwriting Agreement, dated June 1, 2021, by and among Pacific Gas and Electric Company, Barclays Capital Inc., BofA Securities, Inc., Goldman Sachs & Co. LLC and J.P. Morgan Securities LLC (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 1-2348), Exhibit 1.1)
10.12	Underwriting Agreement, dated November 4, 2021, by and among PG&E Recovery Funding LLC, Pacific Gas and Electric Company, Goldman Sachs & Co. LLC and Citigroup Global Markets Inc. (incorporated by reference to Pacific Gas & Electric Company's Form 8-K dated November 4, 2021 (File No. 1-2348), Exhibit 1.1)
10.13	Underwriting Agreement, dated November 10, 2021, by and among Pacific Gas and Electric Company, Barclays Capital Inc., Citigroup Global Markets Inc., MUFG Securities Americas Inc. and Wells Fargo Securities, LLC (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 10, 2021 (File No. 1-2348), Exhibit 1.1)
10.14	Equity Distribution Agreement, dated April 30, 2021, by and among PG&E Corporation, Barclays Capital Inc., BofA Securities, Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC, as sales agents and forward sellers, and Barclays Bank PLC, Bank of America, N.A., Credit Suisse Capital LLC and Wells Fargo Bank, National Association, as forward purchasers (incorporated by reference to PG&E Corporation's Form 8-K dated April 30, 2021 (File No. 1-12609), Exhibit 1.1)
10.15	Pledge Agreement, dated as of July 1, 2020, by and among PG&E Corporation, J.P. Morgan Chase Bank, N.A., as collateral agent, revolving administrative agent and term administrative agent, The Bank of New York Mellon Trust Company, N.A., and the secured representatives party thereto from time to time (incorporated by reference to PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 4.8)
10.16	Purchase Contract and Unit Agreement, dated July 1, 2020, between PG&E Corporation and The Bank of New York Mellon Trust Company, N.A., as purchase contract agent and attorney-in-fact for the holders from time to time as provided therein (incorporated by reference to PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 4.9)
10.17	Custodial Agreement, dated July 1, 2020, between The Bank of New York Mellon Trust Company, N.A., as purchase contract agent and The Bank of New York Mellon Trust Company, N.A., as custodian (incorporated by reference to PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 4.12)
10.18	Tax Benefits Payment Agreement, dated July 1, 2020, between PG&E Corporation and the Fire Victim Trust (incorporated by reference to PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 10.1)
10.19	Registration Rights Agreement, dated as of August 6, 2018, among Pacific Gas and Electric Company, Goldman Sachs & Co. LLC, Mizuho Securities USA LLC, RBC Capital Markets, LLC and SMBC Nikko Securities America, Inc., as representatives of the initial purchasers (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.5)
10.20	Registration Rights Agreement, dated July 1, 2020, between the Fire Victim Trust and PG&E Corporation (incorporated by reference to PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 10.2)
10.21	Amended and Restated Registration Rights Agreement, dated as of July 8, 2021, by and between PG&E Corporation and the PG&E Fire Victim Trust (incorporated by reference to PG&E Corporation's Form 8-K dated July 8, 2021 (File No. 1-12609), Exhibit 4.1)
10.22	Credit Agreement, dated as of July 1, 2020, by and among PG&E Corporation, the several lenders from time to time party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and JPMorgan Chase Bank, N.A., as collateral agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 10.3)

10.23	Amendment No. 1 to Credit Agreement, dated as of June 22, 2021, by and among PG&E Corporation, the several banks and other financial institutions or entities party thereto from time to time, JP Morgan Chase Bank, N.A., as administrative agent and collateral agent (incorporated by reference to PG&E Corporation's Form 8-K dated June 22, 2021 (File No. 1-12609), Exhibit 10.1)
10.24	Term Loan Agreement, dated June 23, 2020, by and among PG&E Corporation, J.P. Morgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to PG&E Corporation's Form 8-K dated June 19, 2020 (File No. 1-12609), Exhibit 10.1)
10.25	Credit Agreement, dated as of July 1, 2020, by and among Pacific Gas and Electric Company, the several lenders from time to time party thereto, JPMorgan Chase Bank, N.A. and Citibank, N.A., as co-administrative agents, and Citibank, N.A., as designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 10.4)
10.26	Amendment No. 1 to Credit Agreement, dated as of June 22, 2021, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time, JP Morgan Chase Bank, N.A., as co-administrative agents and Citibank, N.A,, as designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2021 (File No. 1-2348), Exhibit 10.2)
10.27	Term Loan Credit Agreement, dated as of July 1, 2020, among Pacific Gas and Electric Company, the several lenders from time to time party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No.1-2348), Exhibit 10.4)
10.28	Amendment No. 1 to Credit Agreement, dated as of October 29, 2021, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-12609), Exhibit 10.5)
10.29	Amendment No. 2 to Credit Agreement, dated as of December 31, 2021, by and among Pacific Gas and Electric Company, the Consenting Lenders, the other Lenders (each as defined therein) and JPMorgan Chase Bank, N.A., as administrative agent
10.30	Amendment No. 3 to Credit Agreement, dated as of February 8, 2022, by and among Pacific Gas and Electric Company, the Consenting Lenders (each as defined therein) and JPMorgan Chase Bank, N.A., as administrative agent
10.31	Purchase and Sale Agreement, dated as of October 5, 2020, by and between PG&E AR Facility, LLC, as buyer, and Pacific Gas and Electric Company in its capacity as initial Servicer and in its capacity as Originator (incorporated by reference to PG&E Corporation's Form 8-K dated October 5, 2020 (File No. 1-12609), Exhibit 10.1)
10.32	Amendment No. 1 to Purchase and Sale Agreement, dated as of January 14, 2021, by and between PG&E AR Facility, LLC, as buyer, and Pacific Gas and Electric Company in its capacity as initial Servicer and in its capacity as Originator (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.75)
10.33	Receivables Financing Agreement, dated as of October 5, 2020, by and among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its individual capacity and as initial Servicer, the Persons from time to time party thereto as Lenders and Group Agents and MUFG Bank, Ltd., as Administrative Agent on behalf of the Credit Parties (each as defined therein) (incorporated by reference to PG&E Corporation's Form 8-K dated October 5, 2020 (File No. 1-12609), Exhibit 10.2)
10.34	Amendment No. 1 to Receivables Financing Agreement, dated as of January 14, 2021, by and among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its individual capacity and as initial Servicer, the Persons from time to time party thereto as Lenders and Group Agents and MUFG Bank, Ltd., as Administrative Agent on behalf of the Credit Parties (each as defined therein) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.77)
10.35	Amendment No. 2 to Receivables Financing Agreement, dated as of February 12, 2021, by and among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its individual capacity and as initial Servicer, the Persons from time to time party thereto as Lenders and Group Agents and MUFG Bank, Ltd., as Administrative Agent on behalf of the Credit Parties (each as defined therein) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.78)

10.36		Amendment No. 3 to Receivables Financing Agreement, dated as of May 5, 2021, by and among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its individual capacity and as initial Servicer, the Persons from time to time party thereto as Lenders and Group Agents and MUFG Bank, Ltd., as Administrative Agent on behalf of the Credit Parties (each as defined therein) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-12609), Exhibit 10.2)
10.37		Amendment No. 4 to Receivables Financing Agreement, dated as of September 15, 2021, by and among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its individual capacity and as initial Servicer, the Persons from time to time party thereto as Lenders and Group Agents and MUFG Bank, Ltd., as Administrative Agent on behalf of the Credit Parties (each as defined therein) incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-12609), Exhibit 10.3)
10.38		Collection Account Intercreditor Agreement, dated as of October 5, 2020, by and among Pacific Gas and Electric Company, MUFG Bank, Ltd., and each trustee, indenture trustee, lender administrative agent, collateral agent, purchaser or other party described in Exhibit A therein (incorporated by reference to PG&E Corporation's Form 8-K dated October 5, 2020 (File No. 1-12609), Exhibit 10.3)
10.39		PG&E Fire Victim Trust Share Exchange and Tax Matters Agreement, dated as of July 8, 2021, by and among PG&E Corporation, Pacific Gas and Electric Company, PG&E ShareCo LLC and the PG&E Fire Victim Trust (incorporated by reference to PG&E Corporation's Form 8-K dated July 8, 2021 (File No. 1-12609), Exhibit 10.1)
10.40		Recovery Property Servicing Agreement between PG&E Recovery Funding LLC and Pacific Gas and Electric Company, as Servicer, dated as of November 12, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2021 (File No. 1-2348), Exhibit 10.1)
10.41		Recovery Property Purchase and Sale Agreement between PG&E Recovery Funding LLC and Pacific Gas and Electric Company, as Seller, dated as of November 12, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2021 (File No. 1-2348), Exhibit 10.2)
10.42		Administration Agreement between PG&E Recovery Funding LLC and Pacific Gas and Electric Company, as administrator, dated as of November 12, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2021 (File No. 1-2348), Exhibit 10.3)
10.43		Master Transaction Agreement, dated as of February 2, 2021, by and between Pacific Gas and Electric Company and Golden State Licensing, LLC. (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.80)
10.44		Purchase Agreement, dated as of May 21, 2021, by and between Pacific Gas and Electric Company and Hines Atlas US LP (incorporated by reference to PG&E Corporation's Form 8-K dated May 21, 2021 (File No. 1-2609), Exhibit 10.1)
10.45		First Amendment to Purchase Agreement, dated as of September 14, 2021, by and between Pacific Gas and Electric Company and HNG Atlas US LP (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-12609), Exhibit 10.4)
10.46		Repricing Amendment, dated February 1, 2021, by and among PG&E Corporation, the Consenting Lenders, the New Lenders (each as defined therein) and JPMorgan Chase Bank, N.A. as administrative agent (incorporated by reference to PG&E Corporation's Form 10-Q for the quartered ended March 31, 2021 (File No. 1-12609), Exhibit 10.2)
10.47	**	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of June 3, 2019 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.9)
10.48	**	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective as of June 3, 2019 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.10)
10.49	**	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)
10.50	**	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3)

10.51	**	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2021 (incorporated by reference to PG&E Corporation's Form 8-K dated February 9, 2021 (File No. 1-12609)
10.52	**	Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27)
10.53	**	Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28)
10.54	**	Pacific Gas and Electric Company Officer Relocation Handbook, effective December 15, 2019 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.99)
10.55	**	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective January 1, 2019.(incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.100)
10.56	**	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective February 6, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2014 (File No. 1-2348), Exhibit 10.37)
10.57	**	Postretirement Life Insurance Plan of Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7)
10.58	**	Form of Restricted Stock Unit Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.07)
10.59	**	Form of Restricted Stock Unit Agreement for 2021 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 File No. 1-12609), Exhibit 10.13)
10.60	**	Form of Stock Option Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.08)
10.61	**	Form of Restricted Stock Unit Agreement for 2021 grants to Non-Employee Directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2021 (File No. 1-12609), Exhibit 10.8)
10.62	**	Form of Performance Share Agreement subject to financial goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.04)
10.63	**	Form of Performance Share Agreement subject to safety goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.05)
10.64	**	Form of Performance Share Agreement subject to total shareholder return goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12609), Exhibit 10.06)
10.65	**	Form of Performance Share Unit Agreement subject to customer experience, public safety and financial goals for 2021 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q dated March 31, 2021 (File No. 1-12609), Exhibit 10.14)
10.66	**	Form of Performance Share Unit Agreement subject to total shareholder return goals for 2021 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.15)
10.67	**	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3)
10.68	**	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2)

10.69	**	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
10.70	**	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58)
10.71	**	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No.1-12609), Exhibit 10.24)
10.72	**	Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.01)
10.73	**	Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.2)
10.74	**	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective February 19, 2019 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.119)
10.75	**	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
10.76	**	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
10.77	**	Form of Director and Officer Indemnification Agreement (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2019 (File No. 1-12609), Exhibit 10.8)
10.78	**	Offer Letter between PG&E Corporation and Patricia K. Poppe, effective November 13, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated November 18, 2020 (File No. 1-12609), Exhibit 10.1)
10.79	**	Offer Letter between Pacific Gas and Electric Company and Adam L. Wright, dated January 16, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.7)
10.80	**	Offer Letter between Pacific Gas and Electric Company and Marlene M. Santos, dated January 26, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.9)
10.81	**	Offer Letter between Pacific Gas and Electric Company and Jason M. Glickman, dated March 24, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.12)
10.82	**	Offer Letter between PG&E Corporation and Ajay Waghray, dated July 29, 2020.
10.83	**	Offer Letter between Pacific Gas and Electric Company and Julius Cox, dated January 8, 2021.
10.84	**	Offer Letter between PG&E Corporation and Carla Peterman, dated April 14, 2021
10.85	**	Offer Letter between PG&E Corporation and Sumeet Singh, dated June 30, 2020
10.86	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Patricia K. Poppe, dated January 15, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q dated September 30, 2021 (File No. 1-12609), Exhibit 10.6)
10.87	**	Non-Annual Restricted Stock Unit Award Agreement between Adam L. Wright and PG&E Corporation, dated March 1, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609, Exhibit 10.8)
10.88	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Marlene M. Santos, dated March 15, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.10)

10.89	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Christopher A. Foster, dated March 22, 2021 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2021 (File No. 1-12609), Exhibit 10.11)
10.90		Restricted Stock Unit Award Agreement between PG&E Corporation and William L. Smith, dated August 3, 2020 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.31)
10.91	***	Amended and Restated Performance Share Award Agreement between PG&E Corporation and William L. Smith, dated August 3, 2020 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2020 (File No. 1-12609), Exhibit 10.127)
10.92	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Julius Cox, dated March 1, 2021
10.93	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Carla Peterman, dated June 1, 2021
10.94	**	Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and John Simon, dated August 14, 2020 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.32)
10.95	**	PG&E Corporation 2014 Long-Term Incentive Plan (as adopted effective May 12, 2014 and as last amended effective July 1, 2020) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.40)
10.96	**	PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to Appendix A to PG&E Corporation's definitive proxy statement on Schedule 14A filed on April 8, 2021)
10.97	**	Form of 2020 Performance Share Award Agreement under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.41)
10.98	**	PG&E Corporation 2012 Officer Severance Policy, as amended effective as of September 24, 2020 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-12609), Exhibit 10.42)
10.99	**	PG&E Corporation 2012 Officer Severance Policy, as amended effective as of November 1, 2021
21		Subsidiaries of the Registrant
23.1		PG&E Corporation Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
23.2		Pacific Gas and Electric Company Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24		Powers of Attorney
31.1		Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	***	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1	***	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2		Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS		XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH		XBRL Taxonomy Extension Schema Document
101.CAL		XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB		XBRL Taxonomy Extension Labels Linkbase Document
101.PRE		XBRL Taxonomy Extension Presentation Linkbase Document

101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*	In accordance with Item 601(a)(5) of Regulation S-K, certain schedules (or similar attachments) to this exhibit have been omitted from this filing. Such omitted schedules (or similar attachments) include information relating to the Property. The registrants will provide a copy of any omitted schedule to the Securities and Exchange Commission or its staff upon request. In accordance with Item 601(b)(10)(iv) of Regulation S-K, certain provisions or terms of the Lease Agreement attached as an exhibit to the Agreement have been redacted. Such redacted information includes proprietary information about the Property. The registrants will provide an unredacted copy of the exhibit on a supplemental basis to the Securities and Exchange Commission or its staff upon request.
**	Management contract or compensatory plan, contract or arrangement.
***	Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2021 to be signed on their behalf by the undersigned, thereunto duly authorized.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

PG&E CORPORATION		PACIFIC GAS AND ELECTRIC COMPANY	
(Registrant)		(Registrant)	
/s/ PATRICIA K. POPPE		/s/ ADAM L. WRIGHT	
Patricia K. Poppe		Adam L. Wright	
By:	Chief Executive Officer	By:	Executive Vice President, Operations and Chief Operating Officer
Date:	February 10, 2022	Date:	February 10, 2022
		/s/ MARLENE M. SANTOS	
		Marlene M. Santos	
		By:	Executive Vice President and Chief Customer Officer
		Date:	February 10, 2022
		/s/ JASON M. GLICKMAN	
		Jason M. Glickman	
		By:	Executive Vice President, Engineering, Planning, and Strategy
		Date:	February 10, 2022

Signature	**Title**	**Date**
A. Principal Executive Officers		
/s/ PATRICIA K. POPPE Patricia K. Poppe	Chief Executive Officer (PG&E Corporation)	February 10, 2022
/s/ ADAM L. WRIGHT Adam L. Wright	Executive Vice President, Operations and Chief Operating Officer (Pacific Gas and Electric Company)	February 10, 2022

/s/ MARLENE M. SANTOS Marlene M. Santos	Executive Vice President and Chief Customer Officer (Pacific Gas and Electric Company)	February 10, 2022
/s/ JASON M. GLICKMAN Jason M. Glickman	Executive Vice President, Engineering, Planning, and Strategy (Pacific Gas and Electric Company)	February 10, 2022

B. Principal Financial Officers

/s/ CHRISTOPHER A. FOSTER Christopher A. Foster	Executive Vice President and Chief Financial Officer (PG&E Corporation)	February 10, 2022
/s/ DAVID S. THOMASON David S. Thomason	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 10, 2022

C. Principal Accounting Officer

/s/ DAVID S. THOMASON David S. Thomason	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 10, 2022

C. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)

*	/s/ RAJAT BAHRI Rajat Bahri	Director	February 10, 2022
*	/s/ CHERYL F. CAMPBELL Cheryl F. Campbell	Director	February 10, 2022
*	/s/ KERRY W. COOPER Kerry W. Cooper	Director	February 10, 2022
*	/s/ JESSICA L. DENECOUR Jessica L. Denecour	Director	February 10, 2022
*	/s/ MARK E. FERGUSON III Mark E. Ferguson III	Director	February 10, 2022
*	/s/ ROBERT C. FLEXON Robert C. Flexon	Director Chair of the Board (PG&E Corporation)	February 10, 2022
*	/s/ W. CRAIG FUGATE W. Craig Fugate	Director	February 10, 2022

* /s/ ARNO L. HARRIS Arno L. Harris	Director	February 10, 2022
* /s/ MICHAEL R. NIGGLI Michael R. Niggli	Director	February 10, 2022
* /s/ PATRICIA K. POPPE Patricia K. Poppe	Director	February 10, 2022
* /s/ DEAN L. SEAVERS Dean L. Seavers	Director Chair of the Board (Pacific Gas and Electric Company)	February 10, 2022
* /s/ WILLIAM L. SMITH William L. Smith	Director	February 10, 2022
* /s/ BENJAMIN F. WILSON Benjamin F. Wilson	Director	February 10, 2022
* /s/ ADAM L. WRIGHT Adam L. Wright	Director (Pacific Gas and Electric Company)	February 10, 2022
*By: /s/ JOHN R. SIMON John R. Simon, Attorney-in-Fact		February 10, 2022

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Years Ended December 31,		
(in millions, except per share amounts)	**2021**	**2020**	**2019**
Administrative service revenue	$ 118	$ 127	$ 138
Operating expenses	(124)	(103)	(114)
Interest income	—	—	1
Interest expense	(230)	(149)	(21)
Other income (expense)	(54)	13	10
Reorganization items, net	1	(1,649)	(26)
Equity in earnings of subsidiaries	137	411	(7,622)
Loss before income taxes	(152)	(1,350)	(7,634)
Income tax provision (benefit)	(64)	(46)	8
Net loss	**$ (88)**	**$ (1,304)**	**$ (7,642)**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $3, $7, and $0, at respective dates)	$ 7	$ (17)	$ (1)
Total other comprehensive income (loss)	7	(17)	(1)
Comprehensive Loss	**$ (81)**	**$ (1,321)**	**$ (7,643)**
Weighted Average Common Shares Outstanding, Basic [1]	**2,463**	**1,257**	**528**
Weighted Average Common Shares Outstanding, Diluted [1]	**2,463**	**1,257**	**528**
Net loss per common share, basic	**$ (0.05)**	**$ (1.05)**	**$ (14.50)**
Net loss per common share, diluted	**$ (0.05)**	**$ (1.05)**	**$ (14.50)**

[1] Includes 477,743,590 shares of common stock issued to ShareCo.

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED BALANCE SHEETS

(in millions)	Balance at December 31, 2021	Balance at December 31, 2020
ASSETS		
Current Assets		
Cash and cash equivalents	$ 126	$ 223
Advances to affiliates	21	48
Income taxes receivable	10	12
Other current assets	12	13
Total current assets	**169**	**296**
Noncurrent Assets		
Equipment	2	2
Accumulated depreciation	(2)	(2)
Net equipment	—	—
Investments in subsidiaries	30,232	25,244
Other investments	181	186
Operating lease right of use asset	—	3
Deferred income taxes	297	237
Total noncurrent assets	**30,710**	**25,670**
Total Assets	**$ 30,879**	**$ 25,966**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Long-term debt, classified as current	27	28
Accounts payable – other	200	49
Operating lease liabilities	—	3
Other current liabilities	69	72
Total current liabilities	**296**	**152**
Noncurrent Liabilities		
Debtor-in-possession financing	4,592	4,624
Operating lease liabilities	—	—
Other noncurrent liabilities	168	191
Total noncurrent liabilities	**4,760**	**4,815**
Common Shareholders' Equity		
Common stock	35,129	30,224
Reinvested earnings	(9,286)	(9,198)
Accumulated other comprehensive loss	(20)	(27)
Total common shareholders' equity	**25,823**	**20,999**
Total Liabilities and Shareholders' Equity	**$ 30,879**	**$ 25,966**

PG&E CORPORATION
SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2021	**2020**	**2019**
Cash Flows from Operating Activities:			
Net loss	$ (88)	$ (1,304)	$ (7,642)
Adjustments to reconcile net income to net cash provided by operating activities:			
Stock-based compensation amortization	51	28	43
Equity in earnings (loss) of subsidiaries	(139)	(412)	7,622
Deferred income taxes and tax credits-net	(60)	(50)	—
Reorganization items, net (Note 2)	(32)	1,548	11
Current income taxes receivable/payable	2	—	6
Liabilities subject to compromise	—	12	28
Other	81	97	(62)
Net cash provided by (used in) operating activities	**(185)**	**(81)**	**6**
Cash Flows From Investing Activities:			
Investment in subsidiaries	—	(12,986)	—
Net cash used in investing activities	**—**	**(12,986)**	**—**
Cash Flows From Financing Activities:			
Debtor-in-possession credit facility debt issuance costs	—	—	(16)
Bridge facility financing fees	—	(40)	—
Proceeds from issuance of long-term debt	—	4,660	—
Repayment of long-term debt	(28)	(664)	—
Intercompany note from the Utility	145	—	—
Common stock issued	—	7,582	85
Equity Units issued	—	1,304	—
Other	(29)	—	—
Net cash provided by financing activities	**88**	**12,842**	**69**
Net change in cash and cash equivalents	**(97)**	**(225)**	**75**
Cash and cash equivalents at January 1	**223**	**448**	**373**
Cash and cash equivalents at December 31	**$ 126**	**$ 223**	**$ 448**
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$ (207)	$ (105)	$ (3)
Income taxes, net	1	—	—
Supplemental disclosures of noncash investing and financing activities			
Operating lease liabilities arising from obtaining ROU assets	$ —	$ —	$ 9
Common stock issued in satisfaction of liabilities	—	8,276	—
Increase to PG&E Corporation common stock and treasury stock in connection with the Share Exchange and Tax Matters Agreement	4,854	—	—

PG&E CORPORATION

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2021, 2020, and 2019

(in millions)		Additions			
Description	**Balance at Beginning of Period**	**Charged to Costs and Expenses**	**Charged to Other Accounts**	**Deductions** [2]	**Balance at End of Period**
Valuation and qualifying accounts deducted from assets:					
2021:					
Allowance for uncollectible accounts [1]	$ 146	$ 136	$ —	$ 111	$ 171
2020:					
Allowance for uncollectible accounts [1]	$ 43	$ 138	$ —	$ 35	$ 146
2019:					
Allowance for uncollectible accounts [1]	$ 56	$ —	$ —	$ 13	$ 43

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."

[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

PACIFIC GAS AND ELECTRIC COMPANY

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2021, 2020, and 2019

(in millions)		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions [2]	Balance at End of Period
Valuation and qualifying accounts deducted from assets:					
2021:					
Allowance for uncollectible accounts [1]	$ 146	$ 136	$ —	$ 111	$ 171
2020:					
Allowance for uncollectible accounts [1]	$ 43	$ 138	$ —	$ 35	$ 146
2019:					
Allowance for uncollectible accounts [1]	$ 56	$ —	$ —	$ 13	$ 43

(1) Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."

(2) Deductions consist principally of write-offs, net of collections of receivables previously written off.