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, 2025

☐ **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

PG&E Corporation

Pacific Gas and Electric Company

PG&E Corporation	Pacific Gas and Electric Company
300 Lakeside Drive	**300 Lakeside Drive**
Oakland, California 94612	**Oakland, California 94612**
(Address of principal executive offices) (Zip Code)	(Address of principal executive offices) (Zip Code)
415 973-1000	**415 973-7000**
(Registrant's telephone number, including area code)	(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
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
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, 5% series A redeemable	PCG-PE	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
6.000% Series A Mandatory Convertible Preferred Stock, no par value	PCG-PrX	The New York Stock Exchange

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:	☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

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

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

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, 2025, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$37,246 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 4, 2026:

PG&E Corporation:	2,675,711,544*
Pacific Gas and Electric Company:	264,374,809

*Includes 477,743,590 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 2026 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

Contents

UNITS OF MEASUREMENT

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 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet

GLOSSARY

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

AB	Assembly Bill
Amended Articles	Amended and Restated Articles of Incorporation of PG&E Corporation and the Utility, each filed on June 22, 2020, and for PG&E Corporation, as amended by the Certificate of Amendment of Articles of Incorporation, filed on May 24, 2022
ARO	asset retirement obligation
ASC	accounting standards codification
ASU	accounting standard update issued by the Financial Accounting Standards Board
Bankruptcy Court	the United States Bankruptcy Court for the Northern District of California
CAISO	California Independent System Operator Corporation
Cal Fire	California Department of Forestry and Fire Protection
Cal OES	California Governor's Office of Emergency Services
CARB	California Air Resources Board
CARE	California Alternate Rates for Energy Program
CAVA	Climate Adaptation and Vulnerability Assessment
CCA	Community Choice Aggregator
CEC	California Energy Resources Conservation and Development Commission
CEMA	Catastrophic Event Memorandum Account
Chapter 11	Chapter 11 of Title 11 of the United States Code
Chapter 11 Cases	the voluntary cases commenced by each of PG&E Corporation and the Utility under Chapter 11 on January 29, 2019
Continuation Account	the account established statewide by SB 254 that expands the existing Wildfire Fund
Corporation Revolving Credit Agreement	Credit Agreement, dated as of July 1, 2020, as amended, by and among PG&E Corporation, the several banks and other financial institutions or entities party thereto from time to time and JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent
CPUC	California Public Utilities Commission
CRR	congestion revenue rights
DA	Direct Access
DCPP	Diablo Canyon Power Plant
District Court	United States District Court for the Northern District of California
DOE	United States Department of Energy
DOE Loan Guarantee Agreement	Loan Guarantee Agreement, dated as of January 17, 2025, between the Utility and the DOE
DWR	California Department of Water Resources
Emergence Date	July 1, 2020, the effective date of the Plan in the Chapter 11 Cases
EOEP	Enhanced Oversight and Enforcement Process
EPA	United States Environmental Protection Agency
EPS	earnings per common share
EPSS	Enhanced Powerline Safety Settings
Exchange Act	Securities Exchange Act of 1934, as amended
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
First Mortgage Bonds	bonds issued pursuant to the Indenture of Mortgage, dated as of June 19, 2020 between the Utility and The Bank of New York Mellon Trust Company, N.A., as amended and supplemented
Form 10-K	PG&E Corporation's and the Utility's joint Annual Report on Form 10-K

FRMMA	Fire Risk Mitigation Memorandum Account
GAAP	United States Generally Accepted Accounting Principles
GHG	greenhouse gas
GRC	general rate case
HFTD	high fire threat district
HSMA	Hazardous Substance Memorandum Account
IOUs	investor-owned utility(ies)
IRC	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
LSEs	load serving entities
LTIP	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
NAV	net asset value
NDCTP	Nuclear Decommissioning Cost Triennial Proceeding
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
Oakland General Office	300 Lakeside Drive, Oakland, California, 94612
OEIS	Office of Energy Infrastructure Safety (successor to the Wildfire Safety Division of the CPUC)
PD	proposed decision
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
PSPS	Public Safety Power Shutoff
RA	Resource Adequacy
Receivables Securitization Program	The accounts receivable securitization program entered into by the Utility on October 5, 2020, providing for the sale of a portion of the Utility’s accounts receivable and certain other related rights to the SPV, which, in turn, obtains loans secured by the receivables from financial institutions
ROE	return on equity
ROU asset	right-of-use asset
RPS	Renewables Portfolio Standard
RUBA	Residential Uncollectibles Balancing Account
SB	Senate Bill
SCE	Edison International and Southern California Edison Company
SEC	United States Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
SFGO	The Utility’s San Francisco General Office headquarters complex
SOFR	Secured Overnight Financing Rate
SPV	PG&E AR Facility, LLC
TO	transmission owner
USFS	United States Forest Service
Utility	Pacific Gas and Electric Company
Utility Revolving Credit Agreement	Credit Agreement, dated as of July 1, 2020, as amended, by and among the Utility, the several banks and other financial institutions or entities party thereto from time to time and Citibank, N.A., as Administrative Agent and Designated Agent

VIE(s)	variable interest entity(ies)
VMBA	Vegetation Management Balancing Account
WEMA	Wildfire Expense Memorandum Account
WGSC	Wildfire and Gas Safety Costs
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
WMBA	Wildfire Mitigation Balancing Account
WMCE	Wildfire Mitigation and Catastrophic Events
WMP	wildfire mitigation plan
WMPMA	Wildfire Mitigation Plan Memorandum Account

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 liabilities; ratemaking and regulatory proceedings; capital expenditures; cost savings; load growth; customer rates; 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, and dividends. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "commit," "goal," "target," "will," "may," "should," "would," "could," "potential," "on track," 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 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; and the transfer of ownership of the Utility's assets to municipalities or other public entities, including as a result of the City and County of San Francisco's valuation petition;

- the extent to which the Wildfire Fund, the Continuation Account, and the revised prudency standard under AB 1054 effectively mitigate 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 or the Continuation Account has sufficient remaining funds (which will be reduced as claims are made by California's other participating electric utility companies);

- the risks and uncertainties associated with wildfires that have occurred or may occur in the Utility's service area, 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 July 13, 2021 near the Cresta Dam in the Feather River Canyon in Plumas County, California (the "2021 Dixie fire"), the wildfire that began on September 6, 2022 near Oxbow Reservoir in Placer County, California (the "2022 Mosquito 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; 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; and the risk that the Utility is not able to recover costs from the Wildfire Fund, the Continuation Account, or other third parties or through rates;

- 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; the effectiveness of its system hardening, including undergrounding;

- 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;

- significant changes to the electric power and natural gas industries, including technological advancements, electrification, and the transition to a decarbonized economy; the impact of reductions in Utility customer demand for natural gas; the impact of customer demand falling short of the Utility's forecasts and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, increasing demand for electric power due to data centers and electrification of the transportation, buildings, and other sectors of the economy, and the resulting changes in customer demand for its natural gas and electric services;

- cyber or physical attacks, 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 remediation, compliance and other costs, lost revenues, litigation, investigations, or reputational harm;

- 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, mitigate, 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;

- existing and 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 and the extent to which such costs are borne by PG&E Corporation, including those regarding:

    - wildfires, including inverse condemnation reform, wildfire self-insurance, the Wildfire Fund, the Continuation Account, 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 electric vehicles;

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

    - the regulation of utilities and their affiliates, including the conditions that apply to PG&E Corporation as the Utility's holding company;

    - privacy and cybersecurity; and

    - taxes and tax audits;

- the amounts of fines, penalties, remediation or other obligations resulting from current and future self-reports, investigations or other enforcement actions, agency compliance reports, or notices of violation that could be issued related to the Utility's compliance with laws, rules, regulations, or orders;

- whether the Utility can control its operating costs within the authorized levels of spending; whether the Utility can continue implementing the Lean operating system and achieve projected savings; the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs; the risks and uncertainties associated with inflation (including with respect to raw materials), import tariffs, and trade wars; 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 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, including the extent to which the Utility draws on the DOE Loan Guarantee Agreement;

- the risks and uncertainties associated with the resolution of the matters described in Note 14 of the Notes to the Consolidated Financial Statements under the headings "Wildfire-Related Securities Litigation" and "Indemnification Obligations";

- the risks and uncertainties associated with PG&E Corporation's and the Utility's other ongoing or future litigation, including the extent to which related costs can be recovered through insurance, rates, or from other third parties;

- 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 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 procurement costs through rates;

- 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, volatility in such capital markets, and changes in interest rates;

- the risks and uncertainties associated with high rates for the Utility's customers, including reduced customer demand and approved amounts in the Utility's ratemaking or cost recovery proceedings;

- actions by credit rating agencies to downgrade PG&E Corporation's or the Utility's credit ratings; 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" and Item 7: "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Form 10-K. 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 PG&E Corporation's website, www.pgecorp.com, as promptly as practicable after they are filed with, or furnished to, the SEC. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC located at http://www.sec.gov. 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 "Wildfire and Safety Updates" and "News & Events: Events & Presentations" tabs, respectively, in order to publicly disseminate such information. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on PG&E Corporation's 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 addresses of this website solely for the information of investors and do not intend the address to be an active link. PG&E Corporation and the Utility also make available to investors information about the companies' climate goals and progress in the Corporate Sustainability Report, Climate Strategy Report, and CAVA, which information is not incorporated by reference into this report.

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 for the most recently completed year 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 300 Lakeside Drive, Oakland, California 94612. 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. PG&E Corporation and the Utility are separate entities.

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 difficulties many employees 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 this 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 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, and equitably-paid 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 service 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. PG&E Corporation and the Utility believe 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, employees, and other stakeholders.

The Utility is adapting to severe and extreme climate-driven natural hazards. To build resilience to these hazards, the Utility is working to systematically integrate forward-looking climate data and tools into its decision-making. PG&E Corporation and the Utility also work with policymakers and regulators to advance effective climate change policy in California, and work directly with local governments and communities on adaptation solutions.

PG&E Corporation's and the Utility's 2022 Climate Strategy Report, which is available to the public, describes the companies' climate goals and plans to meet those goals. To meet their longer-term climate goals, PG&E Corporation and the Utility intend to scale their efforts to decarbonize the energy system to accommodate increased vehicle and building electrification, integrate a proliferation of distributed energy resources, and achieve increased utilization of renewable energy combined with investments in the grid and energy storage.

PG&E Corporation and the Utility continue to pursue policies and programs that enable safe, reliable, 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:

- Helped customers avoid emissions and manage energy costs through robust energy efficiency programs.
- Implemented contracts for more than 4.9 GW of battery energy storage capacity, strengthening California's grid efficiency and reliability.
- Helped enable the total number of electric vehicles operating in the Utility's service area to exceed 820,000.
- Brought the total number of interconnected private solar customers to more than 950,000.
- Continued to advance decarbonization initiatives for the Utility's natural gas delivery system, including meeting the CPUC-mandated methane emission reduction target ahead of schedule.

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.

Under cost-of-service ratemaking, a utility's earnings depend on the outcomes of its ratemaking proceedings and its ability to manage costs.

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 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. Costs can also decrease due to improved efficiencies or waste elimination.

PG&E Corporation and the Utility are committed to taking steps to improve their credit ratings and metrics over time. All three credit ratings agencies have increased PG&E Corporation's and the Utility's issuer credit ratings since 2020.

PG&E Corporation's dividend policy entails consistent dividend increases targeting a dividend payout ratio of approximately 20% of core earnings (a non-GAAP financial measure) by 2028. For more information, see Note 6 of the Notes to the Consolidated Financial Statements.

Total capital expenditures recorded in 2025 were $13.4 billion. The Utility's total capital expenditures (including accruals) are forecasted to be $12.4 billion for 2026, $13.4 billion for 2027, $15.4 billion for 2028, $16.3 billion for 2029, and $16.0 billion for 2030. The Utility has identified opportunities for investment in the coming years in addition to its forecast, including investments in transmission for data centers and system investments, transportation electrification capacity, hydroelectric facilities, energy storage, information technology, and automation. The Utility plans to submit a 10-year Electric Undergrounding Plan to the OEIS for review. The Utility will then submit an application requesting conditional approval of the plan's costs to the CPUC. Some of these investments depend on the Utility's ability to generate or obtain the cash to support such investments over this period of time. 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. Additionally, $2.85 billion of fire risk mitigation capital expenditures will be excluded from the Utility's equity rate base pursuant to SB 254.

The Utility expects to make additional capital expenditures, the recovery of which will be subject to future regulatory approval. These expenditures include capital expenditures exceeding amounts authorized in the 2023 GRC final decision and expenditures to be included in a later filing or separate applications. These expenditures are expected to be primarily for wildfire mitigation and electrification.

PG&E Corporation and the Utility are committed to building a safe, reliable, sustainable, and climate-resilient energy system at an affordable cost for 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 could impact different types of customers differently. The Utility has set a goal to increase customer capital investments while also limiting customer bill impacts, including by achieving operating cost savings, seeking efficient financing, and benefiting from electric load growth that reduces other customers' bills. The Utility plans to meet its cost savings goal through increased efficiencies including waste elimination through the Lean operating system. The Utility expects data centers, electric vehicle adoption, and building electrification to drive load growth. For more information see "Competition" below. 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 natural gas and electric bill. The Utility has set a goal to limit average annual customer rate increases to 3%.

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.

Performance: Underpinning the Triple Bottom Line

PG&E Corporation and the Utility use the Lean operating system, which includes five basic "plays": visual management; operating reviews; problem solving; standard work; and waste elimination. Visual management allows teams to see how they are performing against their most important metrics using real-time data. Teams throughout PG&E Corporation and the Utility hold daily, weekly, and monthly operating reviews designed to align the performance of employees closest to the work with the goals and objectives of the companies. 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. Problem solving involves a structured approach to identifying, containing, analyzing, and solving problems in order to capitalize on opportunities. Standard work reduces costs and increases productivity by establishing a consistent company-wide method for completing a task. Waste elimination, the fifth Lean play, involves identifying and eliminating inefficiencies in both process and workflow in a sustainable manner and driving the continued adoption of consistent processes and improvements to financial visibility and controls.

The Utility has responded to wildfire risk by implementing operational changes and investing in safety, including:

- *Enhanced Powerline Safety Settings:* EPSS adjusts the sensitivity of circuit protection devices on selected power lines to de-energize them in less than one-tenth of a second in the event of a disturbance to help prevent potential ignitions. The Utility has enabled EPSS in all high fire risk areas.

- *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 through the use of sectionalizers, which enable more targeted de-energizations, and more granular risk models.

- *Vegetation management:* The Utility inspects its overhead electric distribution and transmission facilities on an annual basis to identify and mitigate vegetation that might grow or fall into utility equipment. Additional inspections are conducted within a subset of HFTD areas. The Utility continues to leverage remote sensing technology to enhance data driven inspection planning and safe work execution.

- *Asset inspections:* Asset inspections identify equipment conditions before failure. The Utility's asset inspection programs continue to grow more risk-informed, thorough, standardized, digitized, and verifiable.

- *System hardening:* System hardening entails repairing, replacing, or eliminating existing power lines in HFTD areas and installing stronger and more resilient equipment. As the Utility's asset inspections have identified less resilient equipment, the Utility has hardened its system by fixing significantly more equipment than in prior years. Hardening methods also include replacing bare overhead conductors with covered conductors and installing stronger poles, removing lines, serving customers through remote grids, or converting lines from overhead to underground.

In recent years, the Utility has introduced or expanded its use of several measures including clearing defensible space around transmission structures, downed conductor detection, partial voltage force outs, and transmission operational controls which further decreased wildfire ignition risk.

The Utility's equipment was not involved in the ignition of any major wildfires in 2025. The Utility experienced a decreased number of CPUC-reportable ignitions in 2025, compared to 2024, due to continued operational improvements.

The Utility is also continuing to invest in a safe and reliable gas system. The Utility's asset safety efforts include pipeline replacements, strength testing, and real-time monitoring systems. Additionally, the Utility educates the public and its workforce regarding safe digging practices and maintains rapid outage response protocols to protect public safety and minimize service disruptions.

The Utility's generation operations focus on safety, compliance, environmental stewardship, and asset reliability. The Utility focuses on continuous improvement, risk informed decision-making, and adhering to industry standards for asset risk management and lifecycle optimization. Work management systems enable the execution and tracking of preventative and corrective maintenance strategies for generation assets.

Regulatory Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. The Utility is regulated primarily at the state level by the CPUC and at the federal level 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 the 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 subject to the Public Utility Holding Company Act as a public utility holding company. The Public Utility Holding Company Act primarily obligates PG&E Corporation and its utility subsidiaries to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

California Public Utilities Commission

The CPUC 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 has also 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 and federal 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 broad 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 gas and electric citation programs adopted by the CPUC, the SED has discretion whether to issue a penalty for each violation. 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. Penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders and may not be recovered through rates or otherwise 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 order instituting investigation 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 electric vehicle 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, "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 siting, construction, operation, maintenance, and safety obligations 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 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 area. The CAISO controls the operation of the electric transmission system in most of California and a small part of Nevada 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 the wholesale power market in most of California and 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 DCPP and the Utility's independent spent fuel storage installation 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 that the Utility incur substantial costs at DCPP, and substantial costs could be required in the future. For more information about DCPP, see Item 1A. Risk Factors and Note 15 of the Notes to the Consolidated Financial Statements in Item 8.

Other Regulators

The CEC is a California agency with responsibility for energy policy and planning. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC establishes forecasts of future energy needs used by the CPUC in determining the adequacy of utilities' and other load-serving entities' electricity procurement. The CEC also promotes energy management and conservation programs, including setting standards for building and appliance energy efficiency and load management programs.

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 the Clean Air Act" 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 facilities.

The Department of Transportation's ("DOT") Pipeline and Hazardous Materials Safety Administration has established regulations regarding the design, construction, operation, maintenance, integrity, safety, and security of natural gas distribution, transmission, and underground storage facilities. The DOT has certified the CPUC to administer oversight and compliance with these regulations for the entities it regulates in California.

The OEIS is a state agency responsible for reviewing and approving or rejecting the Utility's WMP and for evaluating the Utility's implementation of the WMP. The OEIS is also responsible for reviewing and issuing the Utility's annual safety certification, annually reviewing and approving the Utility's executive compensation plan, conducting assessments of the Utility's safety culture, conducting field inspections of wildfire mitigation activities, and reviewing proposed undergrounding plans under SB 884.

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. Delay in obtaining, or failure to obtain and maintain, any such permits, authorizations, or licenses could prevent construction of new facilities, limit or prevent continued operation of existing facilities, or result in significant additional costs or restrictions on operations. 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 or 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.

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. For more information about costs incurred to comply with government regulations and related material effects on PG&E Corporation and the Utility, see Item 1A. Risk Factors, "Liquidity and Financial Resources" and "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.

Hazardous Substance 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 state and federal agencies responsible for implementing environmental laws.

The Utility maintains a comprehensive compliance program but may be liable 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 Department of Toxic Substances Control, 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 the Clean Air Act

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.

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act, which it uses to address GHG emissions.

For information regarding regulation of greenhouse gas emissions, see "Sustainability and Resiliency" below.

Nuclear Fuel Disposal

Nuclear power plant operations produce gaseous, liquid, and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools, and equipment contaminated through use.

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 DCPP 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 DCPP 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.

Ratemaking Mechanisms

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 a reasonable opportunity to earn a return on invested capital. 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).

The Utility's costs of operating and maintaining the utility system are generally approved in the GRC, and costs of equity and long-term debt are generally approved in the CPUC's cost of capital proceedings.

As a result, the Utility's CPUC-jurisdictional revenue requirement is the sum of the following:

- expenses;
- depreciation;
- taxes; and
- the product of the Utility's rate of return (i.e., the cost of capital for long-term debt and equity) and its rate base (i.e. the value of the Utility's investments in generation and distribution assets and general plant).

In addition to the Utility's revenue requirement, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass through" to customers, including its costs to procure electricity and natural gas for customers and to administer public purpose and customer programs.

FERC revenue requirements are set through a FERC-approved formula rate. The Utility's rate of return on electric transmission assets is determined in the FERC TO proceedings.

Customer rates are determined by dividing the revenues that the Utility is authorized to collect from customers by the amount of power that the Utility is forecasted to sell. Increases in load spread the Utility's revenue requirement over a larger usage base, which reduces customer rates, but also increases fuel costs, which are passed through to customers.

Other than certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" from its sales volume through 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 net income is not impacted by fluctuations in sales. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs 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 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, Utility-owned electric generation operations, gas transmission and storage facilities, and an opportunity to earn authorized rate of return from the cost of capital decision. The CPUC conducts a GRC for the Utility every four years. 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 to 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 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 - 2027 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 ratemaking capital structure (i.e., the relative weightings of common stock, preferred equity, and debt for ratemaking) and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The rate of return, or cost of capital, is the weighted average cost of debt, preferred equity, and common stock a utility has issued to finance its utility capital investments. 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 through rates in TO rate cases. 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 previous 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 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. 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 Case for 2024" 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's GRC proceedings or that have been deliberately excluded from such proceedings. 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. Recovery of the costs tracked in these memorandum accounts through rates requires CPUC authorization in separate proceedings, the outcome of which the Utility may be unable to predict. Alternatively, the Utility may seek authority to track incremental costs related to these non-GRC programs in balancing accounts. For more information, see "Regulatory Matters - Cost Recovery Proceedings" in Item 7. MD&A and Note 3 of the Notes to the Consolidated Financial Statements in Item 8.

Diablo Canyon Extended Operations

In lieu of the traditional rate-based return on investment, the Utility receives a fixed payment of $100 million plus a volumetric payment of $13 per MWh generated by DCPP. The fixed payment may be adjusted downward in the event of extended unplanned outages. The amounts of the fixed and volumetric payments are escalated annually by the CPUC. The volumetric payment cannot be realized as shareholder profits or paid out as dividends.

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. 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. In addition, the utilities are required to obtain CPUC approval of their bundled procurement plans ("BPPs"), which are based on customer demand forecasts.

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 Utility recovers its electric procurement costs annually primarily through balancing accounts. See Note 3 of the Notes to the Consolidated Financial Statements in Item 8. 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 CPUC has approved various power purchase agreements into which the Utility has entered 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 CPUC-jurisdictional LSEs in its distribution service area. The Utility may defer procurement of local resources to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high. In addition, the CPUC can order the Utility to seek to procure specific local capacity products, which are included as energy procurement costs. The Utility recovers its administrative and procurement costs associated with its CPE function through a balancing account, subject to demonstrating compliance to the CPUC.

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 generally recovers the cost of gas purchased on behalf of small commercial and residential customers, as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates. If the Utility's costs average less than 99% of a market-based benchmark, then the Utility returns 80% of such savings to customers, subject to a cap; if the Utility's costs average more than 102% of the benchmark, the Utility recovers 50% of such excess costs. As a result, changes in the price of natural gas 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 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 governing payments by shippers (including the Utility) for pipeline service, and the Canada Energy Regulator, the Canadian regulatory agency, approves the applicable Canadian tariffs. 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 DCPP and the Humboldt Bay independent spent fuel installation. 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, generally 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 facilities. If the nuclear decommissioning trusts are overfunded, the amount of such overfunding will be returned to customers, and if the nuclear decommissioning trusts are underfunded, the CPUC must authorize the electric utility to collect these charges from its customers.

For costs related to AROs, see "Asset Retirement Obligations" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

Human Capital

Employees and Contractors

As of December 31, 2025, PG&E Corporation had 10 employees, and the Utility had approximately 29,000 regular employees. Of the Utility's regular employees, approximately 17,500 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") International Federation of Professional and Technical Engineers 20; and the Service Employees International Union Local 24/7 ("SEIU"). The collective bargaining agreements in effect for the IBEW Local 1245, ESC Local 20, and SEIU United Service Workers West expired on December 31, 2025, and have been automatically extended for at least one year while the parties negotiate successor agreements. The automatic extension does not cover general wage increases, which must be separately bargained and agreed to for 2026 and beyond. Under prior agreements, wages increased annually by 3.75% from 2022 through 2025. The IBEW, ESC, and SEIU represent approximately 60% of the Utility's employee workforce and support several areas of the Utility's business, including gas and electric operations. The Utility enjoys stable and productive relationships with its unions and did not experience any work stoppages in 2025.

PG&E Corporation's employees are primarily at the executive management level. The Utility generally has a stable workforce. The Utility's turnover rate for 2025 was 3.8%. Approximately 46% 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. Approximately 19% 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 39,000 individuals from approximately 1,200 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 and equitably-paid 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 virtues that should be cultivated. Each year, the Utility honors employees whose work embodies safety, inclusion and belonging, environmental leadership, innovation, and community service. The Utility conducts employee surveys to measure and improve employee engagement.

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 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 PowerPathway™ workforce development program. Launched in 2008, PowerPathway is a workforce development model to enlarge the talent pool of local and qualified candidates that reflect the communities the Utility serves for skilled craft and utility industry jobs through training program partnerships with educational, community-based and government organizations. 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.

PG&E Corporation and the Utility also provide integrated solutions and programs for employee health and wellness that encompass physical, mental, and financial health. These resources include several on-site or near-site health clinics, annual health screenings, health management tools, ergonomic support, and injury management programs, 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 2025 STIP was focused on company objectives of safety, customer impact, and financial health.

All executive officer compensation is paid by PG&E Corporation.

Safety

The Utility's strategy to deliver safety outcomes remains focused on employees, contractors, and public safety through identification, elimination, and mitigation of high-energy hazards. The Utility's safety metrics include the number of actual serious injuries or fatalities ("SIF-A") and high-energy events that had the potential to result in a serious injury or fatality per 200,000 hours worked ("SIF-P rate"). In 2025, the Utility had four SIF-A incidents, which resulted in one fatality and three serious injuries, and a SIF-P rate of 0.051. The Utility continues to mature its PG&E Safety Excellence Management System, which is a systematic approach to assess risk and evaluate or implement controls for safe operation based on industry standards.

Inclusion and Belonging

PG&E Corporation's and the Utility's goal is to foster a workplace culture of inclusion and belonging where all employees find it enjoyable to work with and for PG&E Corporation and the Utility and feel they belong. These efforts are led by PG&E Corporation's and the Utility's Executive Vice President, Chief People Officer, in partnership with the executive team. The People and Compensation Committee of PG&E Corporation's Board of Directors reviews the companies' inclusion and belonging strategy, practices, and performance.

Key elements of PG&E Corporation's and the Utility's approach to inclusion and belonging include integrating inclusion and belonging into the employee experience with a focus on equity and interrupting bias in hiring, promotion, retention and compensation, heightened cultural awareness programming to encourage understanding and importance of inclusion and belonging, and integrating useful content into training, development, and performance support resources.

Additionally, the Utility's 12 Employee Resource Groups and three Engineering Network Groups execute enterprise-wide employee engagement programming and recognize employees' contributions to organizational culture among the Utility's workforce, communities, and customers. The Employee Resource Groups are open to all employees. Specialized teams facilitate awareness, education, and dialogue and support enterprise inclusion and belonging efforts.

Electric Utility Operations

The Utility generates electricity and provides electric transmission and distribution services throughout its service area in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides electricity, transmission, and distribution services in its service area. 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 "Competition" below.

Electricity Resources

The Utility is required to maintain adequate capacity 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.

In 2025, the Utility estimated total net deliveries of electricity to retail customers were 24,052 GWh. This amount represents the total amount of electricity generated and procured, net of electricity sold into the CAISO open market or to third parties. Utility-owned resources generated approximately 60% of its net delivered electricity.

Of the 2025 estimated total net deliveries of electricity to retail customers from generated and procured resources, approximately 71% was generated from GHG-free resources (34% qualifying renewable energy resources, 32% nuclear, and 5% large hydroelectric), and 29% was generated from natural gas generation resources. Consistent with the RPS requirement, the Utility considers qualifying renewable energy resources to include bioenergy such as biogas and biomass, hydroelectric facilities that are 30 MW or less, wind, solar, and geothermal energy. The Utility's percentage of GHG-free generation decreased in 2025, compared to 2024, because DCPP's generation became attributable to all customers statewide (rather than only the Utility's customers). This change does not represent a decrease in the Utility's ownership of the DCPP resource; rather, the generation associated with this resource became attributed among other LSEs' portfolios. For more information about California's clean energy goals, see further below and in the "Sustainability and Resiliency" section below.

The Utility calculates net deliveries of electricity according to the Power Content Label methodology based on CEC guidelines.

Owned Generation Facilities

As of December 31, 2025, 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	91	2,628
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
Elkhorn Battery Energy Storage System	Monterey County	1	183
Photovoltaic [(3)]:	Various	12	152
Total		**121**	**7,815**

(1) DCPP consists of two nuclear power reactor units, Units 1 and 2. The NRC operating license for Unit 1 expired in 2024, and the operating license for Unit 2 expired in 2025. Both remain in effect pending completion of the ongoing federal relicensing review. For more information, see "Extension of Diablo Canyon Operations" in Item 7. MD&A below.

(2) The Utility's hydroelectric system consists of 94 generating units at 58 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for one small powerhouse 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.

Energy Storage

Energy storage improves system reliability, supports California's decarbonization goals by integrating increased levels of renewable energy, and assists in the event of customer demand growth. The CPUC has established a multi-year energy storage procurement framework, under which the Utility met its requirements to make 580 MW of qualifying storage capacity operational by 2025.

As of December 31, 2025, the Utility owned 183 MW and has contracted for another 3,024 MW of operational energy storage capacity. The Utility has also procured 1,884 MW of battery energy storage to be deployed over the next several years and is working to procure additional battery energy storage to meet its remaining reliability requirements. Separately, the Utility solicited and executed an agreement for long-duration storage, which is storage with at least eight hours of discharge capacity, in order to have this resource online by 2031. In September 2025 the CPUC also conditionally authorized the Utility to recover the costs, up to a cap, associated with increasing the nameplate generating capacity of its Helms Pumped Storage Facility.

Electricity Transmission

Transmission lines deliver electricity at high voltages and over long distances from power sources to transmission substations closer to customers. A strong transmission system supports reliable and affordable service, ability to meet state energy policy goals, and support for a diverse generation mix, including renewable energy.

As of December 31, 2025, the Utility owned approximately 18,000 circuit miles of interconnected transmission lines. The Utility also operated 33 electric transmission substations. 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

Distribution lines allow electricity to travel at lower voltages from substations directly to customers. The Utility's electric distribution network consists of approximately 109,000 circuit miles of distribution lines (of which, as of December 31, 2025, approximately 27% are underground and approximately 73% are overhead), 59 transmission and distribution substations, and 601 distribution substations. 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, 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 customers. In some cases, third parties, such as municipal and other utilities, who generate or procure their own power rely upon the Utility's distribution facilities to deliver their power to them, so that they are able to resell the electricity.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2023 through 2025 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 2025, 2024, or 2023.

	2025	2024	2023
Customers (average for the year)	5,656,450	5,606,873	5,584,185
Deliveries (in GWh) [1]	71,791	74,111	72,933
Revenues (in millions):			
Residential	$ 6,976	$ 7,504	$ 6,041
Commercial	7,022	7,201	5,643
Industrial	1,929	2,065	1,784
Agricultural	1,825	1,815	1,413
Public street and highway lighting	105	103	83
Other, net [2]	72	(47)	136
Subtotal	17,929	18,641	15,100
Regulatory balancing accounts [3]	389	(830)	2,324
Total operating revenues	**$ 18,318**	**$ 17,811**	**$ 17,424**
Selected Statistics:			
Average annual residential usage (kWh)	4,931	5,261	5,217
Average billed revenues per kWh:			
Residential	$ 0.2836	$ 0.2888	$ 0.2356
Commercial	0.2527	0.2528	0.2007
Industrial	0.1403	0.1475	0.1294
Agricultural	0.3636	0.3597	0.2984
Net plant investment per customer	$ 12,710	$ 11,460	$ 10,720

(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 the change in unbilled revenue and amounts subject to refund, 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 area. 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. More than 97% 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 area) 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 2025, the Utility purchased approximately 304,000 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 56% of the total natural gas volume the Utility purchased during 2025.

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. On December 31, 2025, the Utility’s natural gas system consisted of approximately 45,400 miles of distribution pipelines, approximately 5,500 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates seven natural gas compressor stations on its backbone transmission system and one compressor station on its local transmission system that are used to move gas through the Utility’s pipelines. The Utility’s backbone transmission system 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 the transportation of natural gas from various natural gas supply points and interconnection points to the Utility’s natural gas transportation system. These agreements provide transportation service from western Canada to the United States-Canada border, from the United States-Canada border to an interconnection point with the Utility’s natural gas transportation system at the Oregon-California border, from the U.S. Rocky Mountains to an interconnection point with the Utility’s natural gas transportation system at the Oregon-California border, and 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. 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 2025, the Utility continued upgrading transmission pipelines to allow for the use of in-line inspection tools.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2023 through 2025 (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 2025, 2024 or 2023.

	2025	2024	2023
Customers (average for the year) [1]	4,633,685	4,614,080	4,605,628
Gas purchased (MMcf)	223,619	219,758	239,756
Average price of natural gas purchased (price per Mcf)	$ 2.55	$ 1.99	$ 6.91
Bundled gas sales (MMcf):			
Residential	147,827	146,842	171,889
Commercial	56,986	55,174	60,248
Total Bundled Gas Sales	**$ 204,813**	**$ 202,016**	**$ 232,137**
Revenues (in millions):			
Bundled gas sales:			
Residential	$ 3,651	$ 3,089	$ 3,686
Commercial	1,074	984	1,052
Other	101	159	(145)
Bundled gas revenues	4,826	4,232	4,593
Transportation service only revenue	1,937	1,815	1,603
Subtotal	6,763	6,047	6,196
Regulatory balancing accounts [2]	(146)	561	808
Total operating revenues	**$ 6,617**	**$ 6,608**	**$ 7,004**
Selected Statistics:			
Average annual residential usage (Mcf)	37	37	37
Average billed bundled gas sales revenues per Mcf:			
Residential	$ 24.39	$ 20.74	$ 20.73
Commercial	17.59	16.28	14.99
Net plant investment per customer	$ 5,278	$ 5,019	$ 4,749

[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.

Nuclear Operations

The Utility manages its scheduled refueling outages with the objective of minimizing their duration and maintaining high nuclear generating capacity factors, resulting in a stable generation base for the Utility's wholesale and retail power marketing activities. During scheduled refueling outages, the Utility performs maintenance and equipment upgrades to minimize the occurrence of unplanned outages and to maintain safe, reliable operations. For the year ended December 31, 2025, DCPP achieved an average capacity factor of 90%. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, reflect the availability of DCPP's generation to the California electricity market and impact the Utility's performance-based disbursements. For more information, see "Extension of Diablo Canyon Operations" below. Management analyzes capacity factors by comparing DCPP's actual generation to forecasted annual capacity factors, which reflect planned refueling outages, curtailments for condenser cleaning, allowances for minor curtailments resulting from equipment issues, and curtailments for major ocean storms.

In addition to the maintenance and equipment upgrades performed by the Utility during scheduled refueling outages, the Utility has extensive operating and security procedures in place to assure the safe operation of DCPP. The Utility also has extensive safety systems in place designed to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident.

Competition

Trends in Market Demand

The Utility expects customer electric load to increase in coming years primarily as a result of data center usage, electric vehicle adoption, and building electrification. The Utility's ability to accurately predict the location and pace of electric load growth is limited, due to factors such as extent of customer demand, the policy environment, and macroeconomics.

Load growth can reduce other customers' rates when the incremental revenue for the new load is greater than the incremental cost to serve that load. The degree to which load growth reduces other customers' rates will depend on the pricing for the new load, which in turn depends on the unit cost of power for the new load, the costs to construct infrastructure to connect new load, the Utility's cost to serve the new load, and the amount of power used. The Utility is engaged with regulators and other stakeholders on policies, such as cost allocation and rate design frameworks, that support conditions for load growth to improve affordability for customers.

The Utility is also impacted by an increasing quantity of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and customer enrollment in NEM, which allows self-generating customers employing qualifying renewable resources to receive bill credits at the full retail rate, put upward rate pressure on non-NEM customers. The successor to the NEM tariffs, the Net Billing Tariff ("NBT"), reduces but does not eliminate the upward rate pressure. NEM and NBT customers are required to pay an interconnection fee, utilize time of use rates, and pay certain non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay.

The Utility expects customer demand for gas to decrease in the coming years, primarily in response to policies supporting California's climate goals.

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 addition, California law permits cities, counties, and certain other public agencies that have qualified to become CCAs 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.

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 collects 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.

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, in some cases bypassing the Utility's electric infrastructure entirely. Those entities may also rely upon FERC open access tariffs and Utility infrastructure to deliver their energy 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. As a result, the Utility could lose customers (residential, commercial, and industrial) or experience limited growth in the applicable municipality. See "Jurisdictions attempt to acquire the Utility's assets through eminent domain, and third parties attempt to acquire the Utility's customers by bypassing the Utility's electric infrastructure system" in Item 1A. Risk Factors. It is also expected that some publicly-owned utilities will build new or duplicate transmission or distribution facilities to serve existing or potential new Utility customers, bypassing the Utility's electric infrastructure. In some instances, microgrid formation is a key factor in a community's choice to engage governmental entities. Some private companies have also called for changes in law that could allow those companies to privately serve electricity to retail customers without being regulated by the CPUC as public utilities.

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

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

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

Competitive Conditions 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.

Sustainability and Resiliency

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. In the past few years, the Utility's electric distribution system has experienced multiple major outage-causing events associated with extreme heat events and peak loads. Peak loads are expected to increase with increasing temperatures due to direct impacts of ambient temperatures on equipment, increased electricity demand driven by rising air conditioning installation and usage, and continued electrification of transportation and buildings. Higher temperatures may also impact the condition and performance of electric assets, potentially causing deterioration of assets and operational constraints.

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. The risk of damage to or interruptions of operations at facilities such as substations is predicted to increase over time due to sea level rise. Electric and gas equipment and safe access for operations must be prepared for these changing conditions.

Changing precipitation dynamics may impact the Utility's hydroelectric generation. Diminishing future water availability and altered runoff timing during extreme drought poses risks to hydropower generation, operations, and revenue. Also, extreme rain events suggest enhanced risk of hydropower asset damage or failure associated with flooding, which in the worst cases (e.g., uncontrolled water release) may have catastrophic impacts.

Climate change will also continue to intensify the potential for wildfires throughout California. Models incorporating future temperature and precipitation projections suggest that landscape susceptibility to wildfire within the Utility's service area will continue to increase over time, with an expansion of areas that may become HFTD and an intensification of risk within HFTDs. Climate change may also result in increased potential of equipment to cause ignitions or to require PSPS events, as well as the potential for the Utility's equipment to sustain damage from wildfires of any origin.

The worsening conditions across California increase the likelihood and severity of wildfires, including those in which 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.

Greenhouse Gas Emissions Regulation

California laws and regulations have established the following targets:

- A 40% reduction in GHGs by 2030 compared to 1990 levels.
- 60% of retail electricity sales to customers from renewable energy sources by 2030.
- Economy-wide State carbon neutrality by 2045, with net negative emissions thereafter.
- Renewable and zero-carbon resources supplying 90% of utilities' retail electricity sales to customers by 2035, 95% by 2040, and 100% by 2045.

The CARB has also approved GHG emissions reporting and a state-wide, comprehensive 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 under a program known as the cap-and-trade program. In 2025, the changes to state law authorized the program through 2045. Entities with a compliance obligation, including entities that supply electricity and natural gas to California consumers, 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.

The Utility expects all costs and revenues associated with the GHG cap and trade program to be passed through to customers.

The current federal administration has led to uncertainty with regard to what further actions may occur regarding climate change at the federal level.

Mitigating Greenhouse Gas Emissions

The Utility works to mitigate the impact of its operations (including customer energy usage) on the environment, consistent with its commitment to clean and resilient energy for all. See "Emissions Data" below.

PG&E Corporation's and the Utility's 2022 Climate Strategy Report, which is available to the public, describes the companies' climate goals and plans to meet those goals. California laws and regulations have also established targets for GHG emissions. See "Greenhouse Gas Emissions Regulation" above.

The core elements of the Utility's plan to achieve these goals are to:

- reduce its operational emissions;
- maximize electrification where feasible;
- integrate clean electricity supply and load management solutions;
- modernize the gas system into an essential low-carbon resource; and
- offset remaining emissions through high-quality carbon removal solutions.

To reduce operational emissions, the Utility plans to take steps such as reducing methane leaks from its natural gas system, reducing sulfur hexafluoride emissions from the electric system, and electrifying its vehicles, buildings, and facilities.

To maximize electrification, the Utility plans to enable and scale building electrification, supported by building codes and appliance standards that give preference to electric technologies, as well as customers choosing to adopt electric appliances. The Utility can accelerate customer adoption of electric vehicles by offering customer programs, preparing the grid to accommodate new electric vehicle demand, and partnering with innovators on strategies that reduce the cost of owning an electric vehicle.

Load management solutions can increase utilization of the electric infrastructure system, such as by using distributed energy resources more strategically and enabling technologies for customers like bidirectional charging.

To integrate clean electricity supply, the Utility plans to continue to expand GHG-free energy resources and storage capacity over the long-term to meet California's Integrated Resource Planning ("IRP") GHG emissions reduction targets and California's clean energy goals. The Utility expects its GHG-free energy supply to decrease in the near future because, during DCPP's extended operations, the Utility is required to allocate its GHG-free attributes to certain non-Utility providers. The Utility also allocates or sells certain GHG-free energy supply to eligible non-Utility providers in its service territory pursuant to CPUC directives.

Modernizing the gas system involves reducing natural gas carbon intensity through clean fuels and decarbonizing hard-to-electrify customers. Clean renewable fuels such as renewable natural gas, which is derived from organic waste, offers a sustainable alternative to fossil fuel-based gas. While still early in assessing its potential, the Utility may also blend a safe amount of hydrogen for customers in the future, if authorized.

The Utility's ability to implement this plan depends on many factors, such as customers adopting technologies and behaviors that reduce GHG emissions and supportive federal, state, and local climate policies and programs, including regulatory innovations needed to reduce unnecessary new costs for the energy system. New and maturing technologies will need to become effective and efficient. Additionally, the Utility will need to construct infrastructure to serve customer demand and implement load management solutions in a way that is affordable for customers. This affordable construction depends on PG&E Corporation's and the Utility's receiving sufficient funding through their ratemaking applications, dedicating adequate resources, efficiently financing operations, achieving operational cost savings, and benefiting from load growth.

Adapting to the Physical Impacts of Climate Change

Effectively managing physical climate risk will become increasingly critical as the physical impacts of climate change become increasingly frequent and severe over the coming years in California. The Utility's climate resilience efforts continue to focus on characterizing and mitigating the physical impacts of climate change to the Utility's infrastructure, assets, and operations. 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.

A key element of preparing the Utility for the physical risks of climate change is a system-wide CAVA of the Utility's assets, operations, and services, filed with the CPUC in 2024. The CAVA improves the Utility's understanding of its exposure to climate hazards and the sensitivity of assets and operations to these hazards, and provides the basis for necessary climate resilience investments. The Utility is currently developing the next CAVA, which is expected to be more granular than the previous climate vulnerability assessment and will be submitted to the CPUC in 2027.

The Utility is using the CAVA to inform changes to design and construction standards for equipment and facilities in order to increase infrastructure resilience. The Utility plans to continue identifying priority adaptive actions by incorporating results from the CAVA into its risk management, planning, and asset management functions. The Utility works to incorporate scientific information into its operations by reviewing relevant scientific literature. The Utility also works to incorporate customer and community perspectives in the CAVA process based on its engagement with CPUC-designated disadvantaged and vulnerable communities.

The Utility's commitment to increasing resilience to climate change includes aligning its resources and business strategy with California's clean energy goals and advocating for policies and programs that enable safe and reliable energy for the Utility's customers in light of climate change. For example, the Utility believes its strategies to reduce GHG emissions through a portfolio of customer programs, infrastructure improvements, and the use of renewable energy and energy storage will help it adapt to the expected increases in demand for electricity.

PG&E Corporation and the Utility are also making progress on transitioning the gas system to cleaner fuels and supporting efforts to accelerate building electrification. Their objective is to do so in an orderly manner to achieve a positive customer and community experience, while reducing natural gas system investments in targeted electrified communities.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas.

The following table shows the Utility's third-party verified voluntary GHG inventory for 2024, which is the most recent data available. Measuring emissions data involves complex estimates and assumptions, which may change as a result of methodology changes.

PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Sustainability Report.

Emissions Scope	Amount (metric tons CO_2 equivalent)
Scope 1 and 2 emissions (1)	3,391,499
Scope 3 emissions (2)	36,445,372

(1) Scope 1 emissions are direct emissions from the Utility's operations and Scope 2 emissions are indirect emissions from facility electricity use and electric line losses.

(2) Scope 3 emissions are emissions resulting from downstream value chain activities not owned or controlled by the Utility but that which can be indirectly impacted by the Utility's actions. The majority of these emissions came from customer natural gas use.

The Utility achieved a third-party verified CO_2 emissions rate of 16 pounds of CO_2 per MWh for electricity delivered to retail customers in 2024, using the CEC's Power Source Disclosure program methodology.

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 2025 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.

Risks Related to Wildfires

The Wildfire Fund, Continuation Account, and other provisions of AB 1054 and SB 254 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 disallowance cap under AB 1054 and SB 254. Under AB 1054 and SB 254, the Utility is required to maintain a safety certification issued by the OEIS to be eligible for certain benefits, including a cap on Continuation Account reimbursement and all aspects of the reformed prudent manager standard. The 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 certification 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, for the Continuation Account to be available for payment of eligible claims, the Wildfire Fund administrator must determine that the Continuation Account is necessary, the CPUC must authorize extending the non-bypassable charge, and there must be sufficient funds remaining in the Continuation Account. Funds in the Continuation Account may be depleted more quickly than PG&E Corporation and the Utility anticipate as a result of claims made by California's other participating electric utility companies. PG&E Corporation and the Utility are also unable to predict whether the administrator will determine that additional contributions are needed, and if so, the timing of those contingent contributions.

If the Utility is unable to maintain a safety certification or if the Continuation Account is exhausted as a result of claims made by California's other participating electric utility companies or otherwise, the unavailability or insufficiency of the Continuation Account 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 Continuation Account for wildfire-related losses in any year that such losses do not exceed the greater of $1.0 billion in the aggregate and the amount of insurance coverage required under AB 1054.

In addition, there could be a significant delay between the occurrence of a wildfire and when the Utility recognizes accelerated amortization of the Wildfire Fund asset due to the lack of data available to the Utility following a catastrophic event, especially if the wildfire occurs in the service area of another participating electric utility. Participation in the Wildfire Fund and the Continuation Account has had, and is expected to continue to have, a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, and the benefits of participating in the Wildfire Fund and the Continuation Account may not ultimately outweigh the substantial costs of the Utility's contributions to the Wildfire Fund or the Continuation Account. See "Key Factors Affecting Financial Results" and "Critical Accounting Estimates" in Item 7. MD&A.

PG&E Corporation's and the Utility's liabilities for the 2019 Kincade fire, the 2021 Dixie fire, the 2022 Mosquito fire, or the Wildfire-Related Securities Claims could exceed their estimated liabilities, or they could be liable as a result of 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 2021 Dixie fire, and the 2022 Mosquito fire. PG&E Corporation's and the Utility's recorded liability estimates for probable losses in connection with these fires do not include several categories of potential damages that are not reasonably estimable, and are subject to change based on new information. Similarly, PG&E Corporation's and the Utility's costs to resolve the Wildfire-Related Securities Claims could exceed their estimated liabilities. PG&E Corporation and 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 been the subject of investigations, regulatory enforcement actions, and criminal proceedings in connection with wildfires and could be the subject of additional investigations, regulatory enforcement actions, or criminal proceedings in connection with the 2019 Kincade fire, the 2021 Dixie fire, the 2022 Mosquito 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 charges in connection with a wildfire, 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. A hearing on the status of restitution in the Butte County District Attorney's Office's investigation into the 2018 Camp fire has been continued several times, most recently to April 24, 2026. For more information, see Note 15 of the Notes to the Consolidated Financial Statements in the 2024 Form 10-K.

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 ("SDGE") 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 area. 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.

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. The Utility's significant infrastructure investment, vegetation management, and de-energization strategies do not eliminate wildfire risk and may not prevent future wildfires. Once an ignition has occurred, the Utility is unable to control the extent of damages, which are primarily determined by environmental conditions (including weather and vegetation conditions), third-party suppression efforts, and the location of the wildfire.

In addition, wildfires have had and could continue to have (as a result of any future wildfires) adverse consequences on the Utility's proceedings with the CPUC and the FERC, and future regulatory proceedings, including future applications with the OEIS for the annual safety certification. 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 2021 Dixie fire, the 2022 Mosquito fire, or any future wildfires. For more information about the 2019 Kincade fire, the 2021 Dixie fire, the 2022 Mosquito fire, and the Wildfire-Related Securities Claims, 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 costs in excess of insurance coverage in connection with wildfires through rates.

PG&E Corporation's and the Utility's accrued losses for the 2019 Kincade fire and the 2021 Dixie fire of $1.325 billion and $2.15 billion exceed the amounts of available liability insurance coverage of $430 million and $521 million, respectively. PG&E Corporation and the Utility could also incur substantial costs in excess of insurance coverage in connection with the 2022 Mosquito fire. As of December 31, 2025, the Utility has recorded probable recoveries of $632 million and $61 million for the 2021 Dixie fire and 2022 Mosquito fire, respectively, through FERC TO rates or as costs recorded to the WEMA. The Utility would not be allowed to recover these costs in excess of insurance to the extent that the CPUC or the FERC determines that they were incurred imprudently. The inability to recover all or a significant portion of costs in excess of insurance through rates 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, Continuation Account, and other provisions of AB 1054 and SB 254 may not effectively mitigate the risk of liability for damages arising from catastrophic wildfires" above 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. The Utility's wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related losses. The Utility will face a higher likelihood of catastrophic wildfires in its service area 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 sourcing, engaging, training, overseeing, or retaining contract workers it needs to fulfill its mitigation obligations under the WMPs.

Wildfires can occur even when the Utility follows its procedures. 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 or where EPSS has been implemented on Utility equipment. 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.

Risks Related to Regulatory Proceedings, Investigations, and Enforcement Matters

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.

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 have not allowed and may in the future 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, wildfire mitigation and prevention costs before it is clear whether such costs will be recoverable through rates. OEIS has required and may in the future require the Utility to perform work for which the CPUC has not yet authorized, and ultimately may not authorize, recovery. 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 receive reduced revenue without cost recovery 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), whether the CAISO wholesale electricity market continues to function effectively, or compliance with new state laws or policies. See "Trends in Market Demand and Competitive Conditions in the Electricity Industry" in Item 1.

An Enhanced Oversight and Enforcement Process proceeding could result in the Utility losing its license to operate as a utility.

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 an EOEP proceeding, 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, which could be revoked). 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.

PG&E Corporation and the Utility could be adversely affected by legislative and regulatory developments, including through increased compliance costs and penalties.

PG&E Corporation, the Utility, and their operations are subject to extensive federal, state, and local laws, regulations, and orders. The Utility incurs significant capital, operating, and other costs associated with compliance with these rules. These rules could change, which could increase the Utility's compliance obligations and the costs to comply with these rules. Non-compliance with these rules could result in the imposition of material fines, on PG&E Corporation and the Utility, other regulatory exposure and financial risk, significant litigation, and reputational harm.

PG&E Corporation and the Utility may also be affected by changes in laws or regulations, or their application, which could impact their business model, rates, rate base, cost recoveries, revenues, or spending, which in turn could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

For example, the Inflation Reduction Act includes a 15% corporate alternative minimum tax on the adjusted financial statement income ("AFSI") of corporations with average AFSI exceeding $1.0 billion over a three-year period, effective for tax years beginning on or after January 1, 2023. If the law or its interpretation is not changed to permit PG&E Corporation to deduct repairs and maintenance expense, it will incur federal cash liabilities beginning in 2028, the amount of which may become substantial in future years.

The Utility is subject to extensive regulations and enforcement proceedings in connection with compliance with regulations, which could result in penalties.

The Utility is subject to extensive federal, state, and local laws, regulations, and orders, including those regarding customer billing; customer service; affiliate transactions; wildfire mitigation initiatives and WMP targets (including EPSS, PSPS, vegetation management, asset inspections, and system hardening); design, construction, operating and maintenance practices; safety and inspection practices; federal electric reliability standards; environmental compliance; resource adequacy; GHG emissions; renewable energy; privacy, including laws like the California Consumer Privacy Act, as amended ("CCPA"), which permits consumers to exercise certain rights with respect to their personal information, including opting out of receiving certain communications and data sharing with third parties; and compliance with CPUC general orders ("GOs") or other applicable CPUC decisions or regulations.

PG&E Corporation and the Utility collect and retain certain personal information of their customers, shareholders, and employees in connection with operating their business and have certain obligations to protect this data. For example, the CCPA requires a business to implement reasonable security procedures to safeguard personal information against unauthorized access, use, or disclosure. The personal information that PG&E Corporation and the Utility collect, as well as other commercially-sensitive data that they possess, could nonetheless become compromised or improperly disclosed, including through the use of generative artificial intelligence or as a result of a cyber incident, human error, the misappropriation of data, or the occurrence of any of the foregoing at any third party with which PG&E Corporation or the Utility has shared information.

The Utility has been and could in the future be subject to regulatory or governmental enforcement actions with respect to its compliance with such rules.

The Utility is a target of a number of investigations, in addition to certain investigations in connection with wildfires, which could result in enforcement actions. See "Risks Related to Wildfires" above. PG&E Corporation and the Utility could be subject to additional investigations. The Utility is unable to predict the outcome of these pending or potential investigations, including whether they will result in enforcement actions, whether any charges will be brought against the Utility, or the amount of any costs and expenses associated with such investigations.

These investigations or enforcement actions could result in a judgment against the Utility. Failure to comply with laws and regulations could result in material fines, penalties, customer refunds, other payments, increased oversight, and changes in the Utility's operations and business model, reputational harm, and other negative consequences. If the OEIS determines that the Utility has failed to substantially comply with its WMP, the CPUC will assess penalties. These consequences could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. 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.

Jurisdictions attempt to acquire the Utility's assets through eminent domain, and third parties attempt to acquire the Utility's customers by bypassing the Utility's electric infrastructure system.

Local jurisdictions attempt to acquire some of the Utility's assets through eminent domain ("municipalization"). For example, the City and County of San Francisco ("San Francisco") has submitted a petition with the CPUC seeking a valuation of the Utility's electric assets in or serving San Francisco and has expressed an intent to acquire such assets. San Francisco would still need to, among other things, initiate and prevail in an eminent domain action in state court to acquire the Utility's assets, but the Utility may not be successful in defending against such an action or related regulatory proceeding. If municipalization proceedings are permitted to move forward and are successful, the Utility would be entitled to receive the fair market value of the assets that are subject to the takeover effort, as well as associated severance damages, but valuation issues in any municipalization proceeding would be highly contentious and could result in the Utility receiving less than what it believes is just compensation for the applicable assets. Any assets acquired by a third party through eminent domain would be excluded from the Utility's rate base, reducing the Utility's revenues and opportunity to earn a return on such assets. In addition, third parties attempt to bypass the Utility's existing electric infrastructure system to provide retail electric service to discrete geographic areas or specific customers. Utility assets that are targeted for municipalization, as well as existing or potential future Utility customers targeted for electric services by third parties that bypass the Utility's facilities, generally are located in geographic areas that have a lower cost of service relative to billed revenues, so municipalization (or bypass) could negatively impact the affordability of the Utility's service for remaining Utility customers served outside of those geographic areas. A successful municipalization or bypass attempt could also encourage similar attempts by other municipalities or third parties which, if successful, would further divide the Utility's assets and reduce the Utility's rate base, profitability, and affordability for remaining Utility customers. It is also unclear how the CPUC would allocate the compensation received by the Utility for any involuntary sale of its assets between shareholders and customers. As a result of these factors, municipalization or electric bypass could materially affect the Utility's financial condition, results of operations, liquidity, and cash flow.

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. 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, some of which are beyond the Utility's control, including those that arise from:

- the breakdown, failure of, or supply challenges with 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 causes assets to fail and results in uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled or uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a significant prolonged electrical black-out that results in damage to the Utility's equipment or losses for 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 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 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; leaking or spilled insulating fluid from electrical equipment; and release of contaminants caused by the failure of battery energy storage systems; 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, cybersecurity breach, physical attack, or technology failure" 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 such incidents also could lead to significant claims against the Utility.

Further, 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 of facilities. The Utility has less control over contractors than its employees but may retain liability for the quality and completion of the contractor's work. The Utility has been and may in the future be subject to penalties or other enforcement action if a contractor violates applicable laws, rules, regulations, or orders. The Utility also has been and may be subject to liability, penalties, or other enforcement action as a result of personal injury or death caused by third-party contractor actions or inactions.

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 electric power and natural gas industries are undergoing significant changes driven by technological advancements and a decarbonized economy, which could lead to the reduction in demand for natural gas as an energy resource that could impact the Utility's ability to recover the value of its investments through rates.

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, electric vehicles, electric heat pump space conditioning and water heating, battery electric storage, fuel cells, energy efficiency, and demand response technologies. These developments will require further modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grid's capacity to interconnect these resources. In addition, enabling California's clean energy transition will require sustained investments in grid modernization, renewable energy integration projects, energy efficiency programs, energy storage options, electric vehicle infrastructure, and state infrastructure modernization (e.g., rail and water projects). The Utility may be unable to effectively adapt to these potential business and regulatory changes, for instance by failing to meet customer demand for new business interconnections in a timely manner. The CPUC is also 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. If the Utility is unable to effectively adapt to these potential business and regulatory 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 have reduced, and will continue to reduce the use of natural gas. Reducing natural gas use reduces the gas customer base and could diminish the need for gas infrastructure and, as a result, could lead to certain gas assets no longer being "used and useful" (under CPUC precedent, when an asset no longer meets the standard of "used and useful," the asset is removed from rate base, which may result in a reduction in associated rate recovery). In that case, gas assets with substantial investment value could become stranded, resulting in accelerated depreciation or impairment of assets. The Utility could also be required to incur significant decommissioning costs, which may require additional funding. However, even as 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. If the Utility is unable to recover through rates its investments into the natural gas system while still ensuring gas system safety and reliability, its financial condition, results of operations, liquidity, and cash flows could be materially affected.

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, cybersecurity breach, physical attack, or technology failure.

The Utility relies on technology to operate its business, including complex operational, interconnected networks and information technology systems that support critical functions. The Utility also depends on information technology systems to help it monitor and operate the electric grid, detect ignitions and collect other wildfire-related information, process transactions, track and collect revenues, manage customer billing and energy usage data, maintain internal control over financial reporting, and produce accurate and timely financial statements and regulatory filings. These information technology systems allow the Utility to create, collect, use, disclose, store, and otherwise process sensitive information, including regarding customers, employees, and other individuals. These systems can be damaged or disrupted by malicious events such as cyber or physical attacks, or by technology failure.

Cyber attacks targeting utility systems are significant and are continuing to increase in sophistication, magnitude, and frequency. PG&E Corporation and the Utility face various cybersecurity threats, including attempts to gain unauthorized access to their systems and networks, including access to confidential information about the Utility, its customers and employees, denial-of-service attacks, threats to their information technology infrastructure, ransomware, and phishing attacks. These threats come from a variety of highly organized actors, including nation-state actors. PG&E Corporation, the Utility and their third-party vendors have been subject to, and will likely continue to be subject to, threats, breaches, and attempts to gain unauthorized access to the Utility's systems and networks, which could disrupt the Utility's operations. Additionally, artificial intelligence, including generative artificial intelligence, may be used to facilitate or perpetrate these cybersecurity threats. Accordingly, the Utility may not be able to prevent unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations.

The systems and networks of PG&E Corporation and the Utility may also be damaged or disrupted by technology failures due to errors in software or platforms or the inability to appropriately support, update, expand, recover or integrate technology within PG&E Corporation and the Utility's networks.

PG&E Corporation and the Utility add, modify and replace information technology systems and technology vendors from time to time. The Utility is engaged in complex projects regarding its billing and enterprise resource planning systems. Modifying existing systems or implementing new or replacement systems or providers is costly and involves risks, including the risks involved in integrating with the Utility's existing systems and processes, implementing associated changes in accounting procedures and controls, and ensuring that data conversion is accurate and consistent.

Physical attacks targeting the Utility's physical assets or personnel have caused damage, disrupted operations, and caused injuries and could do so in the future.

Any failure, interruption, 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 a safe and efficient manner or at all, damage the Utility's assets or operations or those of third parties, increase costs, and impact the Utility's ability to track or collect revenues and to maintain effective internal controls over financial reporting. 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, lawsuits, and regulatory actions and could result in material fines, 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 business strategy, financial condition, or results of operations.

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 DCPP 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 coverage 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 $332 million of liabilities arising out of each nuclear incident occurring not only at the Utility's DCPP facility but at any other nuclear power plant in the United States.

Operations at the Utility’s two nuclear generation units at DCPP could cease before their planned retirement dates in 2029 and 2030 as a result of new legislation, regulations, orders, or their interpretation, or as a result of operational costs. In such an instance, the Utility would not receive the payments for extended operations at DCPP and could be required to record a charge for the remaining amount of its unrecovered investment. These developments 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 may be unable to attract and retain specialty personnel and may face workforce disruptions.

The Utility’s workforce is aging, and many employees are or will become eligible to retire within the next few years. The Utility’s efforts to recruit and train new field service personnel may be ineffective, and the Utility may be faced with a shortage of experienced and qualified personnel in certain specialty operational positions, such as certain positions at DCPP. Additionally, the Utility could experience workforce disruptions as a result of labor union activity or pandemics. If the Utility were to experience such a shortage or disruptions, work stoppages could occur.

Any such occurrences could materially affect PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows.

PG&E Corporation’s and the Utility’s business activities are concentrated in one industry and in one region.

PG&E Corporation’s and the Utility’s business activities are concentrated in one industry (electric and gas utility) and in one region (Northern and Central California). As a result, their business performance may be affected by events, environmental conditions and economic factors unique to such industry or region, or by regional regulation, legislation or judicial decisions, without the benefit of geographic or business diversification.

Risks Related to Environmental Factors

Severe weather events, 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 area 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 recent wildfire seasons, 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 vegetation growth due to rising temperatures and record rainfall following the drought, and strong wind events, among other environmental factors. Precipitation patterns in California vary significantly from year to year, often leading to periods of severe to extreme drought. Drought conditions often occur and can persist in nearly all of the Utility’s service area depending on the amount of precipitation received in the current or previous water years. More than half of the Utility’s service area is in an HFTD and faces heightened fire risk. Local land use policies and forestry management practices also contribute to these risks by limiting precautionary or remedial activities.

Severe weather events, particularly wildfires, have had a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows, including through significant claims being made against the Utility. In addition, 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, could result in severe business or operational 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 such event 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.

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 imposed by California. In addition, climate hazards have damaged and could again damage the Utility's facilities. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries, or regulators could order the Utility to perform additional work. The Utility anticipates that the increased costs would generally be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase. See "Concerns about high rates for the Utility's customers could negatively impact PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows" below.

Events or conditions caused by climate change could have a material impact on the Utility's operations 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 environmental remediation costs could exceed its liability estimates.

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 or may be identified as a potentially responsible party under federal and state environmental laws. These costs can be difficult to estimate due to uncertainties about the extent of contamination, emerging contaminants, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties, and the Utility's recorded liabilities for known environmental obligations may not accurately estimate its losses.

Environmental remediation costs could also increase in the future as a result of new legislation or regulation. See "PG&E Corporation and the Utility could be adversely affected by legislative and regulatory developments, including through increased compliance costs and penalties" above.

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. For more information, 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 PG&E Corporation's and the Utility's Environment and Financial Condition

The Utility may be unable to manage its costs effectively.

The Utility has set a goal to increase its capital investments to meet safety and climate goals, while also achieving operating cost savings. The Utility's ability to achieve such savings depends, in part, on whether the Utility can improve the planning and execution of its work by continuing to implement the Lean operating system, improve its work management, identify additional opportunities to convert expenses to capital expenditures, and improve organizational design. Even if the Utility is able to reduce some costs through such efforts, other emerging priorities, such as emergency response, public purpose programs, wildfire mitigation initiatives, or California's clean energy transition, could require it to reinvest those savings, which would offset the beneficial effect of such savings on net income. Moreover, under cost-of-service ratemaking, the Utility's earnings depend in large part on its ability to manage costs, and if it is unable to manage costs effectively for the foregoing or any other reasons, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows may be adversely affected.

Concerns about high rates for the Utility's customers could negatively impact PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

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, and the cumulative impact of other public policy requirements, collectively place continuing upward pressure on customers' rates. In particular, the Utility will need to make substantial, sustained investments to its infrastructure to adapt to climate change, enable the clean energy transition, and mitigate wildfire risk. Other factors that could increase customer rates include increases in the Utility's pass-through commodity costs, cost shifts resulting from self-generation of electricity by customers, decreased gas system load, technological developments, changes in federal or state subsidies, a decrease in the volume of sales, or load growth that is slower or fails to reduce other customers' bills to the extent PG&E Corporation and the Utility forecast. High rates could also lead to a decline in the number of customers, which could further increase rates. 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" above.

In addition, the CPUC considers affordability as it adjudicates the Utility's rate cases, and concerns about affordability could cause the CPUC to approve lesser amounts in the Utility's ratemaking or cost recovery proceedings. To relieve upward rate pressure on customers, the CPUC has authorized and may in the future authorize lower revenues than the Utility requested or increase the period over which the Utility is allowed to recover amounts. The Utility's level of authorized capital investment could decline as well, leading to fewer new business interconnections and a slower growth in rate base and earnings. Concerns about affordability could also result in new legislation, see "PG&E Corporation and the Utility could be adversely affected by legislative and regulatory developments, including through increased compliance costs and penalties" above. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

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, 2025, PG&E Corporation had approximately $5.7 billion of outstanding indebtedness (such indebtedness consisting of PG&E Corporation's $2.15 billion aggregate principal amount of convertible senior secured notes due 2027, $1.5 billion aggregate principal amount of Junior Subordinated Notes due 2055, $1.0 billion aggregate principal amount of senior secured notes due 2028, and $1.0 billion aggregate principal amount of senior secured notes due 2030, and the Utility had approximately $55.3 billion of outstanding indebtedness. In addition, PG&E Corporation had $650 million of additional borrowing capacity under the Corporation Revolving Credit Agreement, and the Utility had $3.2 billion of additional borrowing capacity under the Utility Revolving Credit Agreement. In addition, PG&E Corporation and the Utility had outstanding preferred stock with aggregate liquidation preferences of $1.6 billion and $258 million, respectively.

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 or using them for other financing transactions. This 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 such as wildfires; 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, particularly investment grade capital markets. PG&E Corporation's and the Utility's substantial indebtedness may limit their ability to procure additional financing in the future and elevated interest rates, as experienced from 2022 to 2024, may further increase their interest expense. If the Utility were unable to access the capital markets or the cost of financing were to further increase, its financial condition, results of operations, liquidity, and cash flows could be materially affected. Although the Utility is generally entitled to seek recovery of its cost of capital, because such requests are subject to CPUC review, the Utility may not successfully recover its cost of capital. Even when cost recovery is granted, the timing of such recovery will generally not occur until after the costs are required to be paid. 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. In addition, adverse changes in PG&E Corporation’s or the Utility’s credit ratings may increase their cost of capital or restrict their access to the financial markets.

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 their property or business;
- merge or consolidate with other companies;
- enter into any sale-leaseback transactions; and
- enter into swap agreements.

In addition, the Utility’s DOE Loan Guarantee Agreement contains similar covenants as well as certain affirmative and negative covenants, events of default, and prepayment events which are incremental to those contained in the Utility’s credit agreements and indentures.

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. 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. Failure to comply with these covenants could result in an event of default, which, if not cured or waived, could accelerate PG&E Corporation’s or the Utility’s repayment obligations and could result in a default, acceleration or other consequences under other agreements. For example, a default on indebtedness in a principal amount in excess of $200 million could result in a cross-default or cross-acceleration.

PG&E Corporation capital 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 incur in the future 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 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 combined value of 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 combined value of the Equity Securities to increase their proportionate interest in the Equity Securities. Additionally, the application of the Ownership Restrictions, as defined in the Amended Articles, will be determined on the basis of a number of shares outstanding that differs materially from the number of shares reported as outstanding on the cover page of its periodic reports under the Exchange Act because it excludes shares owned by the Utility. See "Tax Matters" in Item 7. MD&A for an example of these calculations. 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 IRC, in a manner that renders the restrictions imposed by Section 382 of the IRC 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 IRC as of such date in the event of an "ownership change" of PG&E Corporation (as defined in Section 382 of the IRC 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 IRC 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.

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, 2025, 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 $38.3 billion and $34.1 billion, respectively. PG&E Corporation may also continue to incur 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 limitations. Under Section 382 of the IRC (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 limitations. In general, an ownership change occurs if the aggregate value of the stock ownership of certain shareholders (generally five percent (5%) 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 IRC. However, whether PG&E Corporation underwent an ownership change as a result of the transactions in PG&E Corporation's equity that occurred pursuant to the Plan or in combination with other changes in the ownership of PG&E Corporation's equity depends on several factors outside PG&E Corporation's control and the application of certain laws that are uncertain in several respects. Accordingly, the IRS may successfully assert that PG&E Corporation has undergone an ownership change pursuant to the Plan. 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 IRC 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. Further, PG&E Corporation's ability to utilize its net operating loss carryforwards is critical to PG&E Corporation's and the Utility's commitment to make certain operating and capital expenditures. Failure to 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 capital stock.

PG&E Corporation is a holding company and relies on dividends, distributions, and other payments, advances, and transfers of funds from the Utility to pay dividends on its capital stock and 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, ability to pay dividends on its capital stock, and ability to meet its debt service obligations under its existing and future indebtedness largely depend upon the earnings and cash flows of the Utility and the distribution of these earnings and cash flows to PG&E Corporation. 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 is restricted by, among other things, applicable laws limiting the amount of funds available for payment of dividends and certain restrictive covenants contained in financing agreements. See "Liquidity and Financial Resources" in Item 7. MD&A. 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 meet its obligations to employees and creditors, and to pay preferred stock dividends, before it can distribute cash to PG&E Corporation. In particular, the CPUC requires PG&E Corporation's and the Utility's Boards 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. The CPUC also regulates the Utility's capital structure. Dividend payments on PG&E Corporation's capital stock are also subject to the discretion of PG&E Corporation's Board of Directors. See Note 6 of the Notes to the Consolidated Financial Statements included in Item 1.

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 make other distributions to PG&E Corporation, which could, in turn, materially and adversely affect PG&E Corporation's ability to pay capital stock dividends or meet other financial obligations.

Inflation and supply chain issues may adversely affect PG&E Corporation and the Utility.

PG&E Corporation and the Utility have observed that prices for equipment, materials, supplies, employee labor, contractor services, variable rate debt, and other inputs have increased and may continue to increase more quickly than expected as a result of inflation, import tariffs, fiscal and monetary policy, or other factors. Additionally, the Utility has experienced shortages in certain items, longer lead times, and delivery delays as a result of domestic and international raw material and labor shortages. If these inflationary pressures and 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 may be unable to secure these resources on economically acceptable terms or offset such costs with increased revenues, operating efficiencies, or cost savings, which may adversely affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

The objective of PG&E Corporation's and the Utility's cybersecurity program is to protect information assets and to mitigate against material cybersecurity threats, data and information compromise, and other risk events that could materially affect the business strategy, results of operations, or financial condition of PG&E Corporation and the Utility. PG&E Corporation's and the Utility's cybersecurity program's strategy is to establish multiple layers of defense through logical and physical security controls so that if any particular control proves insufficient, other controls may capture and mitigate that risk, such as:

- Developing organizational understanding in managing cybersecurity risks to systems, assets, and data by regularly assessing cybersecurity internal controls and program maturity, including engaging independent third parties and participating in external regulatory compliance assessments;
- Assessing, monitoring, and imposing contractual requirements on third-party service providers for cybersecurity risks and for compliance with PG&E Corporation's and the Utility's policies regarding access to company networks, information security, and technology;
- Configuring and monitoring the system; employing policies, controls, and security tools, including training for employees and contractors; and limiting access and operating firewall rules as necessary and appropriate;
- Utilizing multiple government and private assessors, consultants, auditors or other third parties, as well as an internal team, for intelligence gathering, security monitoring, threat hunting, and forensic activities;
- Monitoring emerging data protection laws and regulations and implementing changes to processes designed to comply with any such laws and regulations;
- Responding to cybersecurity incidents as they are detected by containing consequences, investigating causes and impacts, and implementing mitigations;
- Maintaining and utilizing plans for resilience, mitigation, and restoring any capabilities or services that were impaired due to a cybersecurity incident;
- Maintaining cybersecurity liability insurance;
- Maintaining physical controls on a risk-informed basis, including controlling access or monitoring as appropriate; and
- Continuously improving the cybersecurity program by incorporating learning from past experiences and testing, reviewing, and enhancing the controls and capabilities discussed above, including conducting regular cybersecurity incident-response exercises.

PG&E Corporation and the Utility have identified cybersecurity as a key enterprise risk, which they manage through their enterprise risk management system.

PG&E Corporation and the Utility have not experienced any cybersecurity incidents in the last three years that have materially affected, or are reasonably likely to materially affect, the business strategy, results of operations, or financial condition of PG&E Corporation and the Utility. For more information regarding how cybersecurity threats could materially affect PG&E Corporation and the Utility, see "The Utility's operational networks and information technology systems could be impacted by a cyber incident, cybersecurity breach, physical attack, or technology failure" in Item 1A. Risk Factors.

Governance

PG&E Corporation's and the Utility's Boards of Directors, particularly their Safety and Nuclear Oversight Committees, have primary responsibility for overseeing cybersecurity risk management, including reviewing the companies' cybersecurity policies, controls, and procedures. The Safety and Nuclear Oversight Committees participate in cybersecurity risk reviews to promote alignment in operations and asset management in the implementation of mitigation strategies designed to reduce the risk and impact of cybersecurity threats. In the event that the Safety and Nuclear Oversight Committees identify significant exposures, including with respect to cybersecurity, they communicate such exposure to the Boards of Directors to assess PG&E Corporation's and the Utility's risk identification, risk management, and mitigation strategies. Management provides briefings to the Safety and Nuclear Oversight Committees at least annually, as well as briefings on important cybersecurity incidents and threats as necessary and appropriate or as requested. These briefings include describing cybersecurity threats, defenses, mitigation strategies, and risk data analytics that may impact the companies' significant assets.

The Executive Vice President and Chief Information Officer of PG&E Corporation and the Utility and the Senior Vice President, Chief Security Officer, and Chief Data and Analytics Officer of the Utility have collectively over 50 years of prior work experience in various roles involving information technology and cybersecurity functions. They are responsible for assessing and managing cybersecurity risks in collaboration with the enterprise risk management team. Such persons are informed about cybersecurity vulnerabilities and incidents through daily and weekly operating reviews conducted by management and personnel closest to the work as part of the Lean operating system and as otherwise appropriate.

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", "Natural Gas Utility Operations," and "Nuclear 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. Virtually all of the Utility's plant property is subject to the lien of a first mortgage bond indenture.

In June 2025, the Utility closed on its acquisition of the Oakland General Office property, which serves as the headquarters of PG&E Corporation and the Utility. For more information, see Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 3. LEGAL PROCEEDINGS

In addition to the following 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 "Litigation and Other Matters" in Item 7. MD&A, Item 1A. Risk Factors and Notes 9, 14, and 15 of the Notes to the Consolidated Financial Statements in Item 8**.**

SEC rules require disclosure of certain environmental matters when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that the company reasonably believes will exceed a specified threshold. Consistent with SEC rules, each of PG&E Corporation and the Utility has elected to use $1 million as the quantitative threshold for disclosure of such proceedings.

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 the Santa Cruz County Board of Supervisors alleging environmental, vegetation management, and unpermitted work violations. The Utility continues to work with the California Coastal Commission and the Central Coast Regional Water Quality Control Board to resolve any outstanding issues. Violations can result in penalties, remediation, and other relief.

Based on the information available, PG&E Corporation and the Utility believe it is probable that a liability has been incurred. Accordingly, PG&E Corporation and the Utility have recorded charges for amounts that are 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.

Butte Canal Breach

On August 9, 2023, a canal in Butte County owned by the Utility breached. The Central Valley Regional Water Quality Control Board has alleged environmental violations in connection with the breach. Violations can result in penalties, remediation, and other relief.

Based on the information available, PG&E Corporation and the Utility believe it is probable that a liability has been incurred, but the amount of the liability is not reasonably estimable. PG&E Corporation and the Utility do not believe that the resolution of this matter will have a material impact on their financial condition, results of operations, or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following individuals serve as executive officers of PG&E Corporation and the Utility (as applicable), as of February 11, 2026.

Name	Age	Entity At Which Officer is an Executive Officer	Title	Time in Position
Patricia K. Poppe	57	PG&E Corporation	Chief Executive Officer, PG&E Corporation	January 2021 to present
			President and Chief Executive Officer, CMS Energy Corporation	July 2016 to December 2020
Carolyn J. Burke	58	PG&E Corporation	Executive Vice President and Chief Financial Officer, PG&E Corporation	May 2023 to present
			Chief Financial Officer & Executive Vice President, Chevron Phillips Chemical Company LLC	February 2019 to September 2022
Jason M. Glickman	45	PG&E Corporation, Utility	Executive Vice President, Strategy and Growth, PG&E Corporation and Utility	January 2026 to present
			Executive Vice President, Engineering, Planning, and Strategy, Utility	May 2021 to December 2025
			Global Head of Utilities and Renewables, Bain & Company	March 2020 to April 2021
			Partner, Bain & Company	January 2014 to April 2021
Carla J. Peterman	47	PG&E Corporation	President, PG&E Corporation, and Executive Vice President, Customer and Corporate Affairs, PG&E Corporation	January 2026 to present
			Executive Vice President, Corporate Affairs and Chief Sustainability Officer, PG&E Corporation	October 2021 to December 2025
			Executive Vice President, Corporate Affairs, PG&E Corporation	June 2021 to September 2021
			Senior Vice President, Strategy and Regulatory Affairs, Southern California Edison Company	September 2019 to May 2021

			Commissioner, California Public Utilities Commission	December 2012 to December 2018
Marlene M. Santos	65	PG&E Corporation, Utility	Executive Vice President, Enterprise Transformation Officer, PG&E Corporation and Utility	January 2026 to present
			Executive Vice President and Chief Customer and Enterprise Solutions Officer, Utility	October 2023 to December 2025
			Executive Vice President and Chief Customer Officer, Utility	March 2021 to October 2023
			President, Gulf Power Company	January 2019 to March 2021
John R. Simon	61	PG&E Corporation	Executive Vice President, General Counsel and Chief Ethics & Compliance Officer, PG&E Corporation	August 2020 to present
Sumeet Singh	47	PG&E Corporation, Utility	Chief Executive Officer, Pacific Gas and Electric Company, and Executive Vice President, Energy Delivery, Utility	January 2026 to present
			Executive Vice President, Operations and Chief Operating Officer, Utility	March 2023 to December 2025
			Executive Vice President, Chief Risk and Chief Safety Officer, PG&E Corporation and Utility	January 2022 to February 2023
			Senior Vice President and Chief Risk Officer, PG&E Corporation and Utility	February 2021 to December 2021
			Interim President and Chief Risk Officer, Pacific Gas and Electric Company; Senior Vice President and Chief Risk Officer, PG&E Corporation	January 2021 to January 2021
			Senior Vice President and Chief Risk Officer, PG&E Corporation and Utility	August 2020 to December 2021
Alejandro T. Vallejo	49	PG&E Corporation, Utility	Executive Vice President, Chief People Officer, PG&E Corporation and Utility	September 2025 to present
			Chief Risk Officer and Senior Vice President, Ethics and Compliance, PG&E Corporation and Utility	August 2023 to September 2025
			Vice President, Compliance and Ethics, and Deputy General Counsel, Utility	December 2020 to July 2023
Ajay Waghray	64	PG&E Corporation, Utility	Executive Vice President and Chief Information Officer, PG&E Corporation and Utility	January 2024 to present
			Executive Vice President and Chief Information Officer, PG&E Corporation	July 2023 to December 2023
			Senior Vice President and Chief Information Officer, PG&E Corporation	September 2020 to June 2023
Stephanie N. Williams	43	Utility	Vice President, Chief Financial Officer and Controller, Utility	January 2023 to present

Vice President and Controller, PG&E Corporation	January 2023 to present
Vice President, Finance and Planning, Utility	January 2020 to January 2023
Senior Director, Business Finance Electric Operations, Utility	March 2019 to December 2019

PART II

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

As of February 4, 2026, there were 38,490 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 and do not trade in the public market.

For information regarding dividends, 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.

ITEM 6. [RESERVED]

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.

Generally, PG&E Corporation's and the Utility's revenues vary based on the outcomes of ratemaking proceedings and the amount of pass-through costs incurred. See "Ratemaking Mechanisms" in Item 1. Description of the Business regarding how the Utility's revenues are determined. Factors that cause costs to vary include the cost of purchased power and fuel; the costs of procurement storage, transportation of natural gas; weather; criminal, civil and regulatory charges for wildfires; the outcomes of ratemaking proceedings; and increases in interest expense as a result of additional debt issuances.

The discussion related to the results of operations and liquidity for 2024 compared to 2023 is incorporated by reference to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2024, which was filed with the SEC in February 2025.

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 Wildfires, Wildfire Mitigation, and Associated Cost Recovery.* PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows may be materially affected by the costs and effectiveness of the Utility's wildfire mitigation initiatives; the extent of damages from wildfires that do occur; the financial impacts of wildfires; and PG&E Corporation's and the Utility's ability to mitigate those financial impacts with insurance, self-insurance, the Wildfire Fund, the Continuation Account, and regulatory recovery.

  In response to the wildfire threat facing California, PG&E Corporation and the Utility have taken aggressive steps designed to mitigate the threat of catastrophic wildfires. The Utility's wildfire mitigation initiatives include EPSS, PSPS, vegetation management, asset inspections, system hardening, situational awareness tools, and ignition response. These initiatives reduce but do not eliminate the Utility's wildfire risk.

Despite these extensive measures, the Utility's equipment may still be involved in the ignition of future wildfires, including catastrophic wildfires. This risk is exacerbated by a variety of factors, including climate change and severe weather events (in particular, extended periods of seasonal dryness coupled with periods of high wind velocities and other storms), as well as infrastructure and vegetation conditions. Once an ignition has occurred, the Utility may be unable to control the extent of damages, which is determined primarily by environmental and vegetation conditions, third-party suppression efforts, and the location of the wildfire.

PG&E Corporation and the Utility have and will continue to incur substantial expenditures in connection with these initiatives. For more information on incurred expenditures, see Note 3 of the Notes to the Consolidated Financial Statements. The extent to which the Utility will be able to recover these expenditures and other potential costs through rates is uncertain. The Utility could also face fines, penalties, enforcement action, or other adverse legal or regulatory consequences for noncompliance related to wildfire mitigation efforts.

The financial impact of past wildfires is significant. As of December 31, 2025, PG&E Corporation and the Utility have incurred significant liabilities for past wildfires (aggregate liability estimates of $1.325 billion for the 2019 Kincade fire, $2.15 billion for the 2021 Dixie fire, and $350 million for the 2022 Mosquito fire). These estimates do not include all categories of potential damages and losses.

PG&E Corporation and the Utility may be able to mitigate the financial impact of future wildfires in excess of insurance coverage or self-insurance through the Wildfire Fund, the Continuation Account, or cost recovery through rates. Each of these mitigations involves uncertainties, and liabilities could exceed available recoveries. Recorded liabilities in connection with the 2019 Kincade fire and the 2021 Dixie fire have exceeded potential amounts recoverable under applicable insurance policies. See "Loss Recoveries" in Note 14 of the Notes to the Consolidated Financial Statements in Part II, Item 8.

If the eligible claims for liabilities arising from wildfires were to exceed $1.0 billion in any Wildfire Fund or Continuation Account coverage year ("Coverage Year"), the Wildfire Fund or the Continuation Account, as applicable, may be available to reimburse the Utility such excess amount. The Utility's ability to recover wildfire costs depends on the Wildfire Fund or the Continuation Account having sufficient remaining funds, and the Wildfire Fund or the Continuation Account may also be depleted more quickly than expected as a result of claims made by California's other participating electric utility companies. Whether the Utility will be required to reimburse the Wildfire Fund or the Continuation Account depends on its ability to demonstrate to the CPUC that paid wildfire-related costs were just and reasonable.

With respect to the Wildfire Fund, SCE has disclosed that a liability for the wildfire that began on January 7, 2025, in Eaton Canyon in Los Angeles County, California (the "Eaton fire") is probable but not reasonably estimable. PG&E Corporation and the Utility expect to reduce their 20-year estimated life of the Wildfire Fund and assess the Wildfire Fund asset for accelerated amortization based on reliable, publicly available information, including when and if SCE accrues a liability or a Wildfire Fund receivable, respectively (see Note 2 of the Notes to the Consolidated Financial Statements in Part II, Item 8).

Recoveries for the 2019 Kincade fire are also subject to a 40% limitation on the allowed amount of claims arising before emergence from bankruptcy. The Utility has recorded an aggregate Wildfire Fund receivable of $1.150 billion for the 2021 Dixie fire, of which it had received $851 million as of December 31, 2025.

With respect to the Continuation Account, additional uncertainties include whether the Wildfire Fund administrator determines that the Continuation Account is necessary, whether the CPUC authorizes extending the non-bypassable charge, whether the administrator determines that additional contributions are needed and, if so, the timing of those contingent contributions.

The Utility will be permitted to recover its wildfire-related claims in excess of available insurance and legal fees through rates unless the CPUC or the FERC, as applicable, determines that the Utility has not met the applicable prudency standard. The revised prudency standard under AB 1054 has not been interpreted or applied by the CPUC, and it is possible that the CPUC could interpret the standard or apply it to the relevant facts differently from how the Utility has interpreted and applied the standard, in which case the Utility may not be able to recover some or all of the expenses that it has recorded as receivables. As of December 31, 2025, the Utility has recorded receivables for regulatory recovery of $632 million for the 2021 Dixie fire and $61 million for the 2022 Mosquito fire. See "2021 Dixie Fire" and "2022 Mosquito Fire" in Note 14 of the Notes to the Consolidated Financial Statements in Part II, Item 8 for more information.

- *The Timing and Outcome of Ratemaking Proceedings, Other Proceedings, and Legislation.* Regulatory ratemaking proceedings are a key aspect of the Utility's business. 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, administrative and general expenses) and capital costs (e.g., depreciation and financing expenses). Although the Utility generally seeks to recover its recorded costs on a timely basis, greater memorandum and balancing account balances increase the Utility's financing costs. Other proceedings that could impact the Utility's business profile and financial results include actions by municipalities and other public entities to acquire the electric assets of the Utility within their respective jurisdictions. 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 3 and 15 of the Notes to the Consolidated Financial Statements in Part II, Item 8, and "Regulatory Matters" below.

- *There has been increased California state legislative activity and political dialogue in recent years regarding wildfires, energy affordability, and related topics.* The substance and timing of any legislation or other executive or regulatory measures relating to these matters, if such measures are implemented, could have a material impact on PG&E Corporation's and the Utility's business, cash flows, results of operations, and financial condition.

- *PG&E Corporation's and the Utility's Ability to Control Operating and Financing Costs.* Under cost-of-service ratemaking, a utility's earnings depend on its ability to manage costs within the amounts authorized for recovery in its ratemaking proceedings. The Utility has set a long-term goal to increase its capital investments to meet safety and climate goals, while also achieving operating cost savings. The Utility intends to achieve such savings by improving the planning and execution of its business through increased efficiencies, including waste elimination through the Lean operating system. PG&E Corporation and the Utility also work to reduce financing costs by identifying and executing on opportunities to efficiently finance the business, which depend on capital market conditions. Increased volatility in capital markets and continued elevated interest rates may impact PG&E Corporation's and the Utility's ability to obtain financing on acceptable terms or raise the cost of financing, which in turn may negatively impact their financial results.

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 materially from historical results, see Item 1A: "Risk Factors" and "Forward-Looking Statements" above.

Tax Matters

PG&E Corporation had a U.S. federal net operating loss carryforward of approximately $38.3 billion and a California net operating loss carryforward of approximately $34.1 billion as of December 31, 2025.

Under Section 382 of the IRC, 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's or the Utility's ability to use these deferred tax assets to offset taxable income). In general, an ownership change occurs if the aggregate value of 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 and Restated Articles of Incorporation, each filed on June 22, 2020, and PG&E Corporation's Certificate of Amendment of Articles of Incorporation, filed on May 24, 2022 (the "Amended Articles"), contain restrictions on the direct or indirect acquisition or accumulation of PG&E Corporation's stock. These restrictions prevent any person or entity (including certain groups of persons) from acquiring or accumulating 4.75% or more of the combined value of PG&E Corporation's stock, including common stock and mandatory convertible preferred stock prior to the Restriction Release Date (as defined in the Amended Articles) without approval by the Board of Directors of PG&E Corporation.

Shares of PG&E Corporation common stock held directly by the Utility are attributed to PG&E Corporation for income tax purposes and are therefore 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. Accordingly, although PG&E Corporation had 2,675,711,544 common shares outstanding as of February 4, 2026, only 2,197,967,954 common shares (the number of outstanding shares of common stock less the number of shares held directly by the Utility) count as outstanding for purposes of the ownership restrictions in the Amended Articles with the result that the ownership limitation based on the unadjusted outstanding stock of PG&E Corporation is lower than 4.75% and can vary based on the relative value of the common stock and mandatory convertible preferred stock on any particular date. For example, based on the closing prices of PG&E Corporation's common stock and preferred stock as of February 4, 2026, a person's effective Percentage Stock Ownership limitation for purposes of the Amended Articles as of February 4, 2026 was 3.92% of the combined value of PG&E Corporation's outstanding common and preferred stock. The computation of the Percentage Stock Ownership is complex, and persons considering purchasing PG&E Corporation's stock should consult their own tax advisors regarding the application of the ownership restrictions to their particular situation.

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 IRC.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2025 and 2024. 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 income (loss) attributable to common shareholders:

(in millions)	2025	2024	Net Change	Percentage Change
Consolidated Total	$ 2,593	$ 2,475	$ 118	5 %
PG&E Corporation	(472)	(223)	(249)	112 %
Utility	3,065	2,698	367	14 %

PG&E Corporation's net loss primarily consists of interest expense on long-term debt.

Utility

The table below shows the Utility's Consolidated Statements of Income for 2025 and 2024. 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 Net income. The line items with significant net changes are described below.

	Year Ended December 31,			
(in millions)	**2025**	**2024**	**Net Change** [1]	**Percentage Change**
Electric operating revenues	$ 18,318	$ 17,811	$ 507	3 %
Natural gas operating revenues	6,617	6,608	9	— %
Total operating revenues	**24,935**	**24,419**	**516**	**2 %**
Cost of electricity	2,609	2,261	348	15 %
Cost of natural gas	1,107	1,192	(85)	(7) %
Operating and maintenance	11,337	11,787	(450)	(4) %
SB 901 securitization charges, net	35	33	2	6 %
Wildfire-related claims, net of recoveries	100	94	6	6 %
Wildfire Fund expense	352	383	(31)	(8) %
Depreciation, amortization, and decommissioning	4,634	4,189	445	11 %
Total operating expenses	**20,174**	**19,939**	**235**	**1 %**
Operating income	**4,761**	**4,480**	**281**	**6 %**
Interest income	509	589	(80)	(14) %
Interest expense	(2,713)	(2,781)	68	(2) %
Other income, net	328	319	9	3 %
Income before income taxes	**2,885**	**2,607**	**278**	**11 %**
Income tax benefit	(194)	(105)	(89)	85 %
Net income	**3,079**	**2,712**	**367**	**14 %**
Preferred stock dividend requirement	14	14	—	— %
Income Attributable to Common Stock	**$ 3,065**	**$ 2,698**	**$ 367**	**14 %**

Operating Revenues

The Utility's electric and natural gas operating revenues increased by $516 million, or 2%, in 2025 compared to 2024. The increase was primarily due to:

- approximately $650 million in revenues to recover the costs associated with extended operations at DCPP in 2025, with no comparable amount in 2024;
- approximately $500 million in interim rate relief authorized in the 2023 WMCE application (see "2023 WMCE Application" below) in 2025, as compared to 2024;
- approximately $380 million in revenue recognition authorized in the 2024 Transmission Revenue Requirement Reclassification Memo Account ("TRRRMA") final decision in 2025, with no comparable amount in 2024; and
- $348 million in revenues to recover the cost of electricity procurement in 2025, as compared to 2024. These costs are passed through to customers and do not impact Net income,

partially offset by:

- approximately $540 million in interim rate relief authorized in the 2022 WMCE proceeding (see "2022 WMCE Application" below) in 2024, with no comparable amount 2025;
- approximately $430 million in revenues authorized in the 2021 WMCE proceeding (see "2021 WMCE Application" in the 2024 Form 10-K) in 2024, with no comparable amount in 2025;
- approximately $260 million less revenue recognized in 2025, as compared to 2024, authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below);

- approximately $120 million less in revenues authorized in the General Office Sale Memorandum Account ("GOSMA") petition for modification final decision in 2025, as compared to 2024; and

- $85 million less in revenues to recover the cost of natural gas in 2025, as compared to 2024. These costs are passed through to customers and do not impact Net income.

Cost of Electricity

The Utility's Cost of electricity represents the cost of power and fuel used in the Utility's generating facilities and purchased from third parties to serve customers. Cost of electricity includes fuel supplied to other third-party generating facilities, costs to comply with California's cap-and-trade program, realized gains and losses on price risk management activities (see Note 10 of the Notes to the Consolidated Financial Statements in Item 8), and net power purchases from and sales to the CAISO electricity markets and directly from third parties. The Cost of electricity increased by $348 million in 2025 as compared to 2024. This increase was primarily the result of higher procurement costs, including local RA contract costs, FERC approved transmission owner rate case settlement costs, and higher nuclear fuel amortization, partially offset by increased CAISO market net sales, increased sales of various RPS resources, and lower net costs associated with fuel for utility owned generation and contracted generation.

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 Cost of natural gas decreased by $85 million in 2025 as compared to 2024. This decrease was primarily the result of lower GHG emission volumes, favorable price risk management activity resulting from reduced natural gas market volatility, and a reduction in contracted transport capacity, partially offset by higher natural gas procurement costs attributed to increased prices and demand, along with additional contracted storage capacity.

Operating and Maintenance

The Utility's Operating and maintenance expense decreased by $450 million, or 4%, in 2025 compared to 2024. The decrease was primarily due to:

- approximately $560 million in previously deferred expenses authorized in the 2021 WMCE proceeding (see "2021 WMCE Application" in the 2024 Form 10-K) in 2024, with no comparable costs in 2025;

- approximately $540 million of previously deferred expenses authorized in the 2022 WMCE proceeding as part of interim rate relief (see "2022 WMCE Application" below) in 2024, with no comparable costs in 2025;

- approximately $260 million less expense recognized in 2025, as compared to 2024, authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below);

- approximately $210 million in costs related to a FERC order denying the capitalization of certain vegetation management costs and ordering the Utility to reclassify these costs to operating expense in 2024, with no comparable costs 2025; and

- approximately $150 million less expense recognized in 2025, as compared to 2024, authorized in the GOSMA petition for modification final decision,

partially offset by:

- approximately $570 million in costs associated with extended operations at DCPP in 2025, with no comparable costs in 2024;

- approximately $500 million more in previously deferred expenses in 2025, as compared to 2024, related to interim rate relief authorized in the 2023 WMCE proceeding (see "2023 WMCE Application" below); and

- approximately $150 million in previously deferred expenses related to VMBA disallowances in the 2023 WMCE final decision (see "2023 WMCE Application" below) in 2025, with no comparable costs in 2024.

Depreciation, Amortization, and Decommissioning

The Utility's Depreciation, amortization, and decommissioning expenses increased by $445 million, or 11%, in 2025 compared to 2024. The increase was primarily due to the growth in plant balance from capital additions and the recognition of deferred depreciation expense.

Interest Income

The Utility's Interest income decreased by $80 million, or 14%, in 2025 compared to 2024. The decrease was primarily due to a decrease in interest rates and a decrease in interest bearing account balances in 2025, compared to 2024.

Income Tax Benefit

The Utility's Income tax benefit increased by $89 million, or 85%, in 2025 compared to 2024. The increase was primarily due to an increased tax repairs deduction and an additional deduction for certain costs attributable to electric generation.

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

	2025	2024
Federal statutory income tax rate	21.0 %	21.0 %
Increase (decrease) in income tax rate resulting from:		
State income tax (net of federal benefit) [1]	(0.6) %	(0.8) %
Effect of regulatory treatment of fixed asset differences [2]	(27.4) %	(25.2) %
Nontaxable or nondeductible items	1.1 %	0.4 %
Tax credits	(0.9) %	(0.9) %
Changes in unrecognized tax benefits	0.1 %	1.9 %
Other, net	— %	(0.4) %
Effective tax rate	**(6.7)%**	**(4.0)%**

[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, the Utility recognizes the deferred tax impact in the current period and records offsetting regulatory assets and liabilities. Therefore, the Utility's effective tax rate is impacted as these differences arise and reverse. The Utility recognizes 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.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

PG&E Corporation and the Utility expect to be able to generate and obtain adequate cash to meet their cash requirements in the short term and in the long term.

PG&E Corporation and the Utility rely on access to debt and equity markets and credit facilities to finance their capital requirements and support their liquidity needs. 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 service. 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% common equity, 47.5% long-term debt, and 0.5% preferred equity and relies on short-term debt, including its revolving credit facilities, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends 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. Generally, PG&E Corporation and the Utility expect that capital expenditures, debt maturities, and PG&E Corporation capital stock dividends will exceed operating cash flows. As a result, they expect to finance future cash needs in excess of operating cash flows primarily through the capital and credit markets.

Additionally, due to its existing tax attributes, PG&E Corporation does not expect to pay significant federal cash taxes until at least 2031. In 2024, California enacted a new law to suspend the use of net operating losses and limit the use of business credits for tax years 2024 to 2026. As a result, PG&E Corporation expects to pay state income taxes in 2026. See "Tax Matters" above for a discussion of events that could limit PG&E Corporation's ability to use its net operating losses.

PG&E Corporation and the Utility have various contractual commitments which impact cash requirements. These commitments are discussed in "Purchase Commitments" in Note 15 of the Notes to the Consolidated Financial Statements in Part II, Item 8.

As of December 31, 2025, PG&E Corporation and the Utility had access to approximately $4.5 billion of total liquidity comprised of $353 million of the Utility's Cash and cash equivalents, $360 million of PG&E Corporation's Cash and cash equivalents, and $3.8 billion of availability under PG&E Corporation's and the Utility's revolving credit facilities.

Credit Ratings

Credit ratings 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 unsecured credit rating from each of the major credit rating agencies. Contracts which may require collateral postings include the Utility's power and natural gas commodity, transportation, services, and environmental products agreements. Because the Utility's unsecured credit rating remains below investment grade with one of the major credit rating agencies, the Utility generally does not receive unsecured credit from its energy procurement counterparties, and it may be required to increase its collateral postings if its credit rating is downgraded.

Restrictive Debt Covenants

PG&E Corporation's and the Utility's credit agreements and the DOE Loan Guarantee Agreement contain various restrictive financial covenants. One financial covenant requires that the ratio of total consolidated debt to total consolidated capitalization as of the end of each fiscal quarter be no more than 70% for PG&E Corporation and 65% for the Utility.

The failure to comply with the financial covenants contained in these financing arrangements could result in an event of default and the acceleration of the loans under the financing arrangements. PG&E Corporation's and the Utility's various credit agreements and the DOE Loan Guarantee Agreement contain provisions that may result in an event of default if there was a failure to meet payment terms or observe other covenants under other financing arrangements that could result in an acceleration of payments due. Such provisions are referred to as "cross-default" provisions. As of December 31, 2025, PG&E Corporation and the Utility remain in compliance with all financial covenants.

Cash, Cash Equivalents, Restricted Cash, and Restricted 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. In addition to Cash and cash equivalents, the Utility holds Restricted cash and restricted cash equivalents that primarily consist of AB 1054 and SB 901 fixed recovery charge collections that are to be used to service the associated bonds. As of December 31, 2025, PG&E Corporation and the Utility had cash and cash equivalents of $360 million and $353 million, respectively.

Financial Resources

Equity Financings

PG&E Corporation does not expect to undertake any equity issuances through 2030. Factors that could affect PG&E Corporation's planned equity issuances include liquidity and cash flow needs, capital expenditures, interest rates, its share price, its earnings, the timing and outcome of ratemaking proceedings, the timing and terms of other financings, and the outcome of the Wildfire-Related Securities Claims. See "Wildfire-Related Securities Litigation" in Note 14 of the Notes to the Consolidated Financial Statements in Part II, Item 8.

Debt Financings, Credit Facilities, and Term Loans

The Utility generally issues first mortgage bonds and secured debt to meet its long-term funding requirements.

For more information, see "Credit Facilities and Term Loans" and "Long-Term Debt Issuances and Redemptions" in Note 4 of the Notes to the Consolidated Financial Statements in Part II, Item 8.

DOE Loan Guarantee Agreement

As of the date of this report, the Utility has not borrowed any advances under the facility. While the Utility has continued to work with the DOE, the Utility is not able to predict the timing or amount of any funds it may receive from the facility in the future.

For more information about the DOE Loan Guarantee Agreement, see "Liquidity and Financial Resources" in Item 7: "Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2024 Form 10-K.

Other Financings

Citizens Energy Corporation

On January 29, 2025, the Utility entered into an amended and restated agreement with Citizens Energy Corporation ("Citizens") pursuant to which the Utility may lease to Citizens entitlements to certain transmission assets. A portion of the costs associated with each project that is expected to be subject to such a lease will be excluded from the Utility's FERC transmission rates for the duration of the applicable lease. The Utility may offer Citizens up to five lease options over the term of the agreement, for a total investment by Citizens of up to $1.0 billion. If Citizens exercises and the parties close on a lease option, the Utility will receive an upfront payment as prepaid rent for that lease, which is expected to average approximately $200 million per lease, and the rate base associated with the leased entitlements will go into Citizens' rate base, rather than the Utility's, for 30 years. The transactions contemplated by the agreement are subject to FERC and CPUC approvals.

Dividends

PG&E Corporation has announced a dividend policy entailing consistent dividend increases targeting a dividend payout ratio of approximately 20% of core earnings by 2028. No dividend is payable unless and until declared by the applicable Board of Directors. The Board of Directors of PG&E Corporation retains authority to change the common stock dividend target and dividend payout ratio at any time. Future dividend decisions determined by the Board may be impacted by earnings, cash flows, credit metrics, and other business conditions.

For information on dividend declarations and payments, see Notes 6 and 7 to the Consolidated Financial Statements in Part II, Item 8.

Utility Cash Flows

PG&E Corporation's consolidated cash flows consist primarily of cash flows related to the Utility. The following discussion presents the Utility's cash flows for the year ended December 31, 2025 and 2024.

The Utility's cash flows were as follows:

	Year Ended December 31,	
(in millions)	**2025**	**2024**
Net cash provided by operating activities	$ 9,035	$ 8,268
Net cash used in investing activities	(12,316)	(11,375)
Net cash provided by financing activities	2,915	3,348
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**$ (366)**	**$ 241**

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of cash operating expenses. Net cash provided by operating activities increased by $767 million, or 9%, in 2025 compared to 2024. This increase was primarily due to:

- an increase in collections driven in part by recoveries related to DCPP extended operations;
- a decrease in non-wildfire related insurance costs; and
- a decrease in wildfire-related payments, net of recoveries.

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 2021 Dixie fire, and the 2022 Mosquito fire and the timing and amount of any potential related insurance, Wildfire Fund, and regulatory recoveries;
- the timing and amount of costs in connection with future wildfires and the timing and amount of any potential related insurance, including funds available from self-insurance and the Wildfire Fund (see "Wildfire Fund Recoveries under AB 1054 and SB 254" in Note 14 of the Notes to the Consolidated Financial Statements in Part II, Item 8);
- the timing and amount of costs in connection with the portion of the 2023-2025 WMP that are being recovered through rates and the portion of the costs previously incurred in connection with the 2021-2022 WMP that are not currently being recovered through rates (see "Regulatory Matters" below for more information);
- 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; and
- the timing and amount of electric and natural gas commodity price volatility and differences between commodity costs and revenue collections.

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 Part II, Item 8.

Investing Activities

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, customer credit trust, and self-insurance investments which are partially offset by the amount of cash used to purchase new nuclear decommissioning trust, customer credit trust, and self-insurance investments.

The following table summarizes changes in key components of the Utility's investing cash flows for the year ended December 31, 2025, compared to December 31, 2024.

(in millions)	Year Ended December 31,	
Cash used in investing activities - 2024	**$**	**(11,375)**
Capital expenditures		(1,418)
Net purchases related to customer credit trust investments		(186)
Net purchases related to self-insurance investment and other investing activities		663
Net increase in cash used in investing activities		**(941)**
Cash used in investing activities - 2025	**$**	**(12,316)**

Net cash used in investing activities increased by $0.9 billion, or 8%, in 2025 compared to 2024. This increase was primarily due to a $349 million payment for the purchase of the Oakland General Office, as discussed in Note 2 of the Notes to the Consolidated Financial Statements in Part II, Item 8, along with higher investments in new business, capacity projects, and distribution system hardening. These increases were partially offset by lower funding related to self-insurance investments in 2025 compared to 2024.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will invest $12.4 billion in capital expenditures in 2026.

Financing Activities

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, the Utility's future cash flows from financing activities will be affected by the timing and outcome of the Utility's financings, dividend payments, and equity contributions from PG&E Corporation.

The following table summarizes changes in key components of the Utility's financing cash flows for the year ended December 31, 2025, compared to December 31, 2024.

(in millions)	Year Ended December 31,	
Cash provided by financing activities - 2024	**$**	**3,348**
Net borrowings under credit facilities		6,574
Net borrowings under term loan		2,675
Repayments of long-term debt, net of proceeds		(1,113)
AB 1054 recovery bonds issuance		(1,409)
Short-term debt issuance		(1,999)
Dividend payments		(325)
Proceeds from DWR loan		(980)
Equity contributions from PG&E Corporation		(3,785)
Other financing activities		(71)
Net decrease in cash provided by financing activities		**(433)**
Cash provided by financing activities - 2025	**$**	**2,915**

Net cash provided by financing activities decreased by $433 million, or 13%, during the year ended December 31, 2025 as compared to the same period in 2024. The decrease was primarily due to:

- $3.8 billion decrease in equity contributions received from PG&E Corporation;
- $1.1 billion increase in repayments of long-term debt, net of proceeds;
- $2.7 billion decrease in net borrowings under term loan;
- $1.4 billion of proceeds related to the issuance of senior secured recovery bonds under the AB 1054 securitization in 2024, with no similar transaction in 2025;

- $2.0 billion decrease in proceeds related to short-term debt issuance;
- $980 million decrease in proceeds related to the DWR loan; and
- $325 million increase in dividend payments.

Partially offset by:

- $6.6 billion increase in net borrowings under credit facilities.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the OEIS, 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. Except as otherwise noted, PG&E Corporation and the Utility are unable to predict the timing or outcome of the following proceedings.

Key updates to regulatory matters include the following:

- In February 2026, the CPUC issued a final decision in the Utility's 2023 WMCE proceeding, approving recovery of $1.9 billion of costs.
- In February 2026, the OEIS issued a final decision approving the Utility's 2026–2028 WMP. In December 2025, the Utility submitted its 2025 safety certificate request to OEIS.
- In December 2025, the CPUC issued a final decision in the Utility's 2026 Cost of Capital proceeding that set the Utility's ROE at 9.98% effective January 1, 2026 and approved a yield spread adjustment.
- In December 2025, the CPUC approved a resolution that updated CPUC guidelines for implementation of the SB 884 undergrounding program.
- In November 2025, the Utility filed the Kincade and Dixie AB 1054 Wildfire Cost Review and Recovery Proceeding application requesting recovery of approximately $1.59 billion of WEMA costs, review of costs drawn from the Wildfire Fund, and recovery of $314 million of CEMA costs.
- In August 2025, the FERC approved an all-party settlement in the Utility's Transmission Owner Rate Case for 2024 (the "TO21" rate case).
- In August 2025, the CPUC issued a final decision that increases the cost cap for 2025 and 2026 by an aggregate $2.38 billion in connection with the Order Instituting Rulemaking ("OIR") to Establish Energization Timelines.
- In September 2025, the CPUC issued a final decision approving $1.06 billion in cost recovery in the 2022 WMCE proceeding.
- In May 2025, the Utility filed its 2027 GRC application with the CPUC.

Cost Recovery Proceedings

Periodically, costs arise that could not have been anticipated by the Utility during CPUC GRC proceedings or that have been deliberately excluded from such proceedings. For instance, 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 later authorize recovery of costs tracked in memorandum accounts if the costs are deemed incremental and prudently incurred. The CPUC may also authorize memorandum and balancing accounts with limitations or caps on cost recovery. These accounts, which include the CEMA, WEMA, FRMMA, WMPMA, VMBA, WMBA, among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, other wildfire prevention-related costs, and certain third-party wildfire claims. While the Utility generally expects such costs to be recoverable, the CPUC may authorize the Utility to recover less than the full amount of its costs.

In recent years, the Utility has recorded significant amounts to these accounts. Because rate recovery may require CPUC authorization of the costs in these accounts, there can be a delay between when the Utility incurs costs and when it may recover those costs. As of December 31, 2025, the Utility had recorded an aggregate amount of approximately $2.2 billion in costs for the CEMA, WEMA, FRMMA, WMPMA, VMBA, and WMBA, substantially all of which was accounted for as long term. See Note 3 of the Notes to the Consolidated Financial Statements in Part II, Item 8.

If the amount of the costs recorded in these accounts increases, or the delay between incurring and recovering costs lengthens, PG&E Corporation and the Utility may incur additional financing costs. If the Utility does not recover the full amount of its recorded costs, the difference between the recorded and recovered amounts would be written off as a non-cash disallowance. Such disallowances could materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Part II, Item 8, and "Wildfire Mitigation and Catastrophic Events Cost Recovery Applications" and "Wildfire and Gas Safety Costs Recovery Application" below.

Key updates to the Utility's cost recovery proceedings are summarized in the following table:

Proceeding	Request [(1)]	Status
2022 WMCE	$1.36 billion of cost recovery	Final decision authorizing $1.06 billion of total cost recovery issued September 2025.
2023 WMCE	$2.18 billion of cost recovery	Final decision authorizing $1.9 billion of costs issued February 2026.
2024 WMCE	$596 million of cost recovery	Application filed November 2024.
2023 WGSC	$2.5 billion of cost recovery	Application filed June 2023. Decision authorizing $516 million of interim rate relief adopted March 2024.
Kincade and Dixie AB 1054	Review of 2019 Kincade fire and 2021 Dixie fire costs, including recovery of approximately $1.9 billion	Application filed November 2025.

[(1)] The revenue requirement amounts requested do not include interest.

Wildfire Mitigation and Catastrophic Events Cost Recovery Applications

2022 WMCE Application

On December 15, 2022, the Utility filed an application with the CPUC requesting cost recovery of approximately $1.36 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.29 billion (the "2022 WMCE application"). The costs addressed in the 2022 WMCE 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 2021. The recorded expenditures consisted of $1.2 billion in expenses and $136 million in capital expenditures.

On September 26, 2025, the CPUC issued a final decision adopting the settlement agreement and authorizing total cost recovery for this matter of $1.06 billion. The final decision disallowed $217 million in VMBA costs.

2023 WMCE Application

On December 1, 2023, the Utility filed an application with the CPUC requesting cost recovery of approximately $2.18 billion of recorded expenditures, resulting in a proposed revenue requirement of approximately $1.86 billion (the "2023 WMCE application"). The costs addressed in the 2023 WMCE 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 2022.

The recorded expenditures consist of $1.6 billion in expenses and $559 million in capital expenditures. Of these amounts, approximately 15% of expense, or $239 million, and 30% of capital expenditures, or $167 million, relate to the Utility's response to the 2022-2023 extreme winter storms CEMA event.

On September 16, 2024, the CPUC issued a final decision on interim rate recovery that grants the Utility interim rate relief of $944 million, plus interest, subject to refund, to be recovered over at least 17 months starting October 1, 2024.

On February 5, 2026, the CPUC voted out a final decision, which approved recovery of $1.9 billion of costs. The final decision denied recovery of $173 million in vegetation management costs.

2024 WMCE Application

On November 21, 2024, the Utility filed an application with the CPUC requesting cost recovery of approximately $596 million of recorded expenditures in the CEMA and other accounts, resulting in a revenue requirement of approximately $435 million (the "2024 WMCE application"). The costs addressed in the 2024 WMCE application include those incurred in connection with rebuild and restoration activities, certain catastrophic wildfire and weather events, and other programs supporting gas, customer, and climate initiatives. These costs were incurred primarily in 2023.

The recorded expenditures consist of $80 million in expense and $516 million in capital expenditures. Of these amounts, approximately $50 million of expense and $396 million of capital expenditures relate to community rebuild and restoration activities and other catastrophic events included in the CEMA.

Wildfire and Gas Safety Costs Recovery Application

On June 15, 2023, the Utility filed a WGSC application with the CPUC requesting cost recovery of approximately $2.5 billion of recorded expenditures related to wildfire mitigation costs and gas safety and electric modernization costs.

The recorded expenditures for wildfire mitigation consist of $726 million in expenses and $1.5 billion in capital expenditures and cover activities during the years 2020 to 2022. The recorded expenditures for gas safety and electric modernization efforts consist of $120 million in expenses and $118 million in capital expenditures and cover activities during the years 2017 to 2022. If approved, the requested cost recovery would result in an aggregate revenue requirement of $688 million. The costs addressed in the WGSC application are incremental to those previously authorized in the Utility's 2020 GRC and other proceedings.

The Utility recorded these costs to the memorandum and balancing accounts as set forth in the following table:

(in millions)	**Recorded Costs**	
WMPMA	$	2,095
FRMMA		165
Gas storage balancing account		101
In line inspection memorandum account		92
Other		45
Total	**$**	**2,498**

In connection with the WGSC application, the Utility also requested interim rate relief of $583 million. The remaining $105 million would be recovered after the CPUC issues a final decision. On March 7, 2024, the CPUC approved a final decision authorizing the Utility to recover $516 million in interim rates to be recovered over at least 12 months starting April 1, 2024.

On June 12, 2025, the CPUC issued a decision extending the statutory deadline in the proceeding from June 30, 2025 to March 31, 2026.

Review and Recovery of Costs Associated with the 2019 Kincade Fire and 2021 Dixie Fire Under AB 1054 Proceeding Application

On November 14, 2025, the Utility filed an application with the CPUC seeking review and recovery of costs associated with the 2019 Kincade fire and 2021 Dixie fire. The application seeks (1) recovery of $1.59 billion of costs recorded to the WEMA and not covered through the Wildfire Fund or insurance, (2) review of the costs recorded to the WEMA and drawn from the Wildfire Fund, and (3) recovery of $314 million of costs recorded to the CEMA.

The Utility had drawn approximately $674 million from the Wildfire Fund at the time of the application. This amount will increase as the Utility continues to resolve claims and draw from the Wildfire Fund. The CPUC may require the Utility to reimburse the Wildfire Fund to the extent that amounts drawn from the Wildfire Fund are determined not to be just and reasonable. See Note 14 of the Notes to the Consolidated Financial Statements.

The scoping memo indicates that a PD will be issued by November 2026. That deadline could be extended by six months.

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 "cost of capital" proceedings to adjust its regulated return on rate base. The Utility's future earnings will depend on the revenue requirements authorized in such rate cases.

Decisions in GRC proceedings have historically been expected prior to the commencement of the period to which the rates would apply. In recent decades, decisions in GRC proceedings have been delayed. Delayed decisions 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 risks associated with the lower level of work achieved compared to that funded by the CPUC.

Key updates to the Utility's forward-looking rate cases are summarized in the following table:

Rate Case	Request	Status
2027 GRC	Revenue requirement of $16.64 billion for 2027	Filed May 2025. A PD is expected by March 2027 and a final decision by May 2027.
2026 Cost of Capital	Increase ROE to 11.30% and cost of debt to 5.04%	Final decision approving ROE of 9.98% and cost of debt of 5.04% issued December 2025.
Transmission Owner Rate Case for 2024 (TO21)	Revenue requirement of $2.78 billion for 2024, subject to true-up and refund	Accepted December 2023, except as to CAISO adder. All other issues resolved August 2025.

2027 General Rate Case

On May 15, 2025, the Utility filed its 2027 GRC application with the CPUC. In the 2027 GRC, the CPUC will determine the annual amount of revenue requirements that the Utility will be authorized to collect through rates from 2027 through 2030 to recover its anticipated costs for gas distribution, transmission and storage, electric distribution, and electric generation and to provide the Utility an opportunity to earn its authorized rate of return. On November 10, 2025, the Utility submitted errata to update its GRC opening testimony and revenue requirement request.

The table below compares the portion of CPUC jurisdictional revenue requirements and weighted-average rate base that are requested in the GRC proceeding, as updated, from 2027 through 2030 to the amounts adopted for 2026 in the 2023 GRC and other cost recovery proceedings:

Year	Requested revenue requirement (in billions)	Requested weighted-average GRC rate base
2026 (as adopted)	$ 15.4	54.0
2027	16.6	67.0
2028	17.6	73.4
2029	18.7	79.4
2030	19.8	85.4

In the 2027 GRC application, the Utility proposed various safety, resiliency, and clean energy investments. Among other things, the Utility proposed to invest a total of approximately $45.0 billion between 2027 and 2030 in CPUC-jurisdictional assets. The proposed investments would support wildfire safety (including undergrounding 307 miles of electrical lines in 2027 and 400 miles per year for 2028 through 2030 until a 10-year undergrounding plan is approved), grid modernization, gas system safety, clean energy, and resilience.

In addition, the Utility requested authorization to establish new balancing accounts for new business capital spend and employee medical expenses.

The Utility is not seeking 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 July 31, 2025, the CPUC issued a scoping memo that modifies the standard rate case plan schedule. The scoping memo indicates that the CPUC will issue a PD by March 2027 and a final decision by May 2027.

Cost of Capital Proceedings

2026 Cost of Capital Application

On March 20, 2025, the Utility (along with the other IOUs in California) submitted its 2026 Cost of Capital application.

On December 18, 2025, the CPUC issued a final decision and approved the following cost of capital rates, which went into effect beginning January 1, 2026:

	Cost	Weight	Weighted Cost
Return on Common Equity	9.98%	52.00%	5.19%
Return on Preferred Equity	5.52%	0.50%	0.03%
Return on Long-term debt	5.04%	47.50%	2.39%

The decision approved a revenue credit to return the benefit of potential DOE loan draws to customers and a temporary yield spread adjustment to compensate the Utility for its actual cost of short-term debt above the commercial paper rate. The yield spread adjustment for 2026 is 125 basis points. The decision also continued the Cost of Capital mechanism pursuant to which the Utility's ROE will be adjusted and the cost of debt will be trued up to the most recent recorded cost of debt upon a significant change in rates.

Transmission Owner Rate Case for 2024

On October 13, 2023, the Utility filed its TO21 rate case with the FERC. In the filing, the Utility forecasted a 2024 retail electric transmission revenue requirement of $2.83 billion. The Utility requested that FERC approve a 12.37% base ROE as well as a 0.5% adder for its participation in the CAISO. The TO21 filing also addresses the Utility's capital structure and several new issues including wildfire self-insurance recovery from transmission customers.

On December 29, 2023, the FERC issued an order accepting the TO21 filing subject to refund, establishing a January 1, 2024 effective date, and establishing a settlement and hearing process, but denying the 0.5% ROE adder for participation in the CAISO, which results in a forecast transmission revenue requirement of $2.78 billion. On January 29, 2024, the Utility filed a request for rehearing of the FERC's denial of the 0.5% ROE adder for participation in the CAISO. On June 12, 2024, the FERC issued an order denying the Utility's request for rehearing. On June 18, 2024, the Utility and other California IOUs filed an appeal of the FERC's order denying the Utility's request for rehearing. On July 11, 2025, the Ninth Circuit Court of Appeals denied the utilities' joint appeal. On August 20, 2025, the Utility and California IOUs sought en banc review from the Ninth Circuit. On September 15, 2025, the Ninth Circuit denied en banc review. On October 7, 2025, the Utility and California IOUs filed a petition for certiorari with the Supreme Court.

On March 21, 2025, the Utility filed with the FERC a settlement in the TO21 rate case. On August 5, 2025, the FERC issued a decision approving the settlement and resolving all contested issues in the proceeding, as well as specific wildfire cost recovery issues raised by stakeholders in prior proceedings related to the Utility's TO tariff. The decision sets a base ROE of 10.38%, a fixed capital structure with common equity weighted at 50.0%, preferred equity at 0.3%, and long-term debt at 49.7%.

On December 1, 2025, the Utility filed with the FERC the TO annual update for rate year 2026, which included the provisions of the TO21 settlement. The revenue requirement for rates that went into effect on January 1, 2026 is $2.6 billion, which represents a decrease from the 2025 revenue requirement of $2.9 billion.

Other Regulatory Proceedings

2026-2028 Wildfire Mitigation Plan

On April 4, 2025, the Utility submitted to the OEIS its 2026-2028 WMP, which it revised on July 28, 2025. The 2026-2028 WMP provides a comprehensive overview of the Utility's wildfire mitigation strategy and incorporates lessons learned from previous years and emerging best practices. On February 5, 2026, the OEIS issued a final decision approving the Utility's 2026–2028 WMP.

Extension of Diablo Canyon Operations

On September 2, 2022, SB 846 became law. SB 846 supports the extension of operations at DCPP through no later than 2030, with the potential for an earlier retirement date. Under the legislation, the Utility continues to operate DCPP on behalf of all CPUC-jurisdictional LSEs, and all customers of those LSEs are responsible for the cost of extended operations.

The key steps to continued operations are NRC license renewal and approvals from several California state agencies. As of December 31, 2025, the Utility has received all necessary state approvals except for approval from the Central Coast Region Water Quality Control Board. The CPUC's approval is subject to the following conditions: (1) the NRC continues to authorize DCPP operations; (2) the loan agreement authorized by SB 846 is not terminated; and (3) the CPUC does not make a future determination that DCPP extended operations are imprudent or unreasonable.

On November 7, 2023, the Utility submitted an application for license renewal with the NRC. On December 19, 2023, the NRC deemed the application sufficient, which allows continued operations at DCPP past the plant's current licenses until the relicensing review is complete. In June 2025, the NRC issued the final safety evaluation report and supplemental environmental impact statement.

SB 884 10-Year Distribution Undergrounding Program

On March 7, 2024, the CPUC approved a resolution that establishes an expedited utility distribution infrastructure undergrounding program pursuant to Public Utilities Code Section 8388.5. The resolution addressed the process and requirements for the CPUC's review of any large electrical corporation's 10-year distribution infrastructure undergrounding plan and conditional approval of its related costs. On December 4, 2025, the CPUC approved a resolution that updated and refined the prior resolution and instructed the Utility to file a joint application with SCE and SDGE requesting approval of a proposal to resolve several cost recovery issues, including the benefit-cost ratio and audit methodologies, not addressed in the resolution. On February 9, 2026, the utilities submitted that filing.

On February 20, 2025, the OEIS adopted final program guidelines. The OEIS has indicated that it will issue separate compliance guidelines.

LEGISLATIVE AND REGULATORY INITIATIVES

SB 254

On September 19, 2025, SB 254 became law and became effective. Among other things, the law provides for the Continuation Account, which is designed to provide additional liquidity to reimburse catastrophic wildfire-related claims incurred by large electric corporations (as defined in SB 254), if the Wildfire Fund is depleted. Each of California's large electric IOUs has elected to participate in the Continuation Account. The Continuation Account would be similar to the Wildfire Fund, except:

- The Continuation Account would provide up to $18 billion of liquidity. If the Wildfire Fund administrator determines that the Continuation Account is necessary prior to December 31, 2028, the CPUC will consider whether to extend the non-bypassable charge on customers from 2036 through 2045. If the CPUC extends the non-bypassable charge on customers, the participating utilities' annual $300 million contributions will be extended from 2029 through 2045.

The Wildfire Fund administrator is also authorized to determine if additional annual contributions are needed, in which case the participating utilities will contribute an additional $3.9 billion in equal installment payments over five years. If the administrator winds up and terminates the Continuation Account before the final installment payment is made, the utilities will return one-half of the unpaid installment payments as rate credits to customers.

The Utility's allocation among the participating utilities for these contributions is 47.85%.

- If a utility is required to reimburse the Continuation Account, the amount of reimbursement will be reduced by the amount of contributions for which the utility has not claimed a reduction.

- The disallowance cap on reimbursements, which is equal to 20% of the equity portion of the utility's electric transmission and distribution rate base, is determined based on the year of the ignition. This revised disallowance cap applies to fires occurring before or after the effective date of SB 254.

Assets in the Continuation Account are separate from the Wildfire Fund and are not available for fires ignited before the effective date of SB 254.

For fires that destroy 1,000 or more structures, SB 254 gives the participating utilities a right of first refusal over insurers' transactions to sell their right of subrogation, reimbursement, or recovery.

SB 254 also prohibits the Utility from including in its equity rate base the first $2.9 billion that it first expends on fire risk mitigation capital expenditures approved by the CPUC on or after January 1, 2026. The Utility expects to finance this amount with securitization.

SB 254 requires the Wildfire Fund administrator to prepare a report by April 1, 2026 that evaluates and sets forth recommendations on new models or approaches that mitigate damage, accelerate recovery, and responsibly and equitably allocate the burdens from natural catastrophes, including catastrophic wildfires, earthquakes, and other natural disasters, across stakeholders, including insurers, communities, homeowners, landowners, governments, large electrical corporations, and local publicly owned electric utilities, to complement or replace the Wildfire Fund.

LITIGATION AND OTHER MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to matters described in Notes 14 and 15 of the Notes to the Consolidated Financial Statements in Part II, Item 8 and in "Regulatory Matters" above 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.

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 substances; 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 does not have a balancing account for costs in excess of its revenue requirement for natural gas transportation and storage service to non-core customers. 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. PG&E Corporation uses value-at-risk to measure its shareholders' exposure to these risks. The value-at-risk was approximately $4 million and $5 million at December 31, 2025 and 2024, 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, 2025 and 2024, if interest rates changed by one percent for all PG&E Corporation and Utility variable rate long-term debt, short-term borrowings, and cash investments, the pre-tax impact on net income over the next 12 months would be $37 million and $6 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. See Note 4 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 or 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, 2025	$ 1,048	4	$ 714
December 31, 2024	$ 1,114	4	$ 708

[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.

Contributions to the Wildfire Fund

PG&E Corporation and the Utility account for shareholder contributions to the Wildfire Fund by recognizing an asset, amortizing the asset ratably over the life of the fund based on an estimated period of coverage, and accelerating amortization of the asset when it is determined probable and estimable that the Wildfire Fund longevity has declined, as further described below.

AB 1054 did not specify a period of coverage; therefore, this accounting treatment is subject to significant accounting judgments and estimates. In estimating the longevity of the fund, PG&E Corporation and the Utility use a dataset with historical, publicly available fire-loss data caused by electrical equipment to create Monte Carlo simulations of expected loss. The simulation began with 12 years of publicly available fire-loss data, and PG&E Corporation and the Utility add an additional year of data each subsequent year. In addition to historical data, significant assumptions also include the estimated amount of Wildfire Fund claim payments, the number of years of fire-loss data, estimated costs of wildfire settlement claims from other participating utilities, CPUC's determinations of whether costs were just and reasonable in cases of electric utility-caused wildfires and the amounts required to be reimbursed to the Wildfire Fund, and the effects of climate change. Due to the significant judgment required to estimate the life of the Wildfire Fund, there is a high degree of uncertainty for many of these assumptions, and so subsequent changes to the available information could materially impact the remaining estimated life of the fund. Based upon the outcome of newly run Monte Carlo simulations when known information becomes available, PG&E Corporation and the Utility may determine to increase or decrease, as applicable, the estimated life of the fund. For instance, in 2024, a re-evaluation in the estimate resulted in the Wildfire Fund life increasing from 15 to 20 years.

Estimates for the useful life of the Wildfire Fund and the accelerated amortization of the fund, respectively, are based on a variety of assumptions and are subject to uncertainty and change as additional information becomes publicly available. The estimated life of the Wildfire Fund reflects wildfire risk in the state, while accelerated amortization anticipates potential draw-downs of the Wildfire Fund. Both of these estimates have a high degree of uncertainty since they rely on a number of assumptions, such as potential wildfire claim payments, future wildfire activity, regulatory decisions, and any potential disclosed cost of wildfires caused by other participating electric utilities.

SCE has disclosed that a liability for the Eaton fire is probable but not reasonably estimable. PG&E Corporation and the Utility expect to reduce their 20-year estimated life of the Wildfire Fund and assess the Wildfire Fund asset for accelerated amortization based on reliable, publicly available information, including when and if SCE accrues a liability or a Wildfire Fund receivable, respectively. As a result, the Wildfire Fund asset could be amortized down to zero in the near future. For every $5 billion of Wildfire Fund receivables recorded by a participating utility, PG&E Corporation and the Utility expect that they would record approximately $1 billion of accelerated amortization.

As of December 31, 2025, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $377 million in Other noncurrent liabilities, $297 million in Current assets - Wildfire Fund asset, and $3.7 billion in Noncurrent assets - Wildfire Fund asset in the Consolidated Balance Sheets. During the years ended December 31, 2025 and 2024, the Utility recorded amortization and accretion expense of $352 million and $383 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.

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 Monte Carlo simulation creates annual distributions of potential losses due to fires that could be attributed to the participating electric utilities. Initial use of five years of historical data, with average annual statewide claims or settlements of approximately $6.5 billion versus 12 years of historical data, with average annual statewide claims or settlements of approximately $2.9 billion, would have resulted in a six year amortization period. As of December 31, 2025, a 10% change to the assumption around current and future mitigation effort effectiveness would increase the amortization period by ten years assuming greater effectiveness and would decrease the amortization period by five years assuming less effectiveness.

Other assumptions used to estimate the useful life include the disclosed cost of wildfires caused by participating 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 participating electric utilities. Significant changes in any of these estimates could materially impact the amortization period.

For more information, see "Contributions to the Wildfire Fund and the Continuation Account" in Note 2 and "Wildfire Fund Recoveries under AB 1054 and SB 254" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8.

Loss Contingencies

PG&E Corporation and the Utility record an estimated liability when they determine that a loss is probable, and they can reasonably estimate the loss or a range of losses. As discussed below, PG&E Corporation and the Utility have recorded material estimated liabilities for various wildfire-related, enforcement, environmental remediation, and other legal matters. For more information about PG&E Corporation's and the Utility's accounting policies and sources of uncertainty in these estimates, see Notes 14 and 15 of the Notes to the Consolidated Financial Statements in Item 8.

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.

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. The process for estimating liabilities requires management to exercise significant judgment based on a number of assumptions and subjective factors, including 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, and estimates based on currently available information and prior experience. As more information becomes available, including from potential claimants as litigation or resolutions progress, management estimates and assumptions regarding the potential financial impacts of wildfire events may change.

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.

With respect to environmental remediation, as of December 31, 2025 and 2024, the Utility's estimated undiscounted gross environmental liabilities were $1.2 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.

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 arising before August 1, 2023. PG&E Corporation and the Utility record a receivable for a recovery when they determine that it is probable that they will recover a recorded loss, 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, communications 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.

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. The Utility continues to apply ASC 980, *Regulated Operations*. Refer to "Regulation and Regulated Operations" in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. As of December 31, 2025, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $22.6 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $24.3 billion.

Determining probability requires significant judgment by management and includes consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or 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, FRMMA, WMPMA, VMBA, WMBA, and MGMA among others, allow the Utility to track the costs associated with work related to disaster and wildfire response, and other wildfire prevention-related costs. While the Utility generally believes such costs are recoverable, rate recovery requires CPUC authorization in separate proceedings or through a GRC.

Additionally, SB 901 provides a mechanism for the CPUC to 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 customer harm threshold ("CHT"). SB 901 required the CPUC to establish the CHT 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. The Utility must evaluate the likelihood of recovery in future rates each period. In 2022, PG&E Corporation and the Utility recorded a regulatory asset associated with SB 901. As of December 31, 2025, the SB 901 regulatory asset was approximately $5.1 billion. See Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

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 2 and 3 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, escalation rates, credit-adjusted risk-free rates, and estimated decommissioning dates. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation. The Utility performs detailed cost studies of its nuclear generation facilities in conjunction with the NDCTP, most recently performed in 2021, and updates its nuclear AROs accordingly, unless circumstances warrant more frequent updates. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plant. 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.

At December 31, 2025, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was approximately $5.4 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 3 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 2026 was 7.0%, gradually decreasing to the ultimate trend rate of approximately 4.5% in 2036 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 7.0% compares to a ten-year actual return of 5.7%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 831 Aa-grade non-callable bonds at December 31, 2025. 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 2025 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2025
Discount rate	(0.50)%	$ 13	$ 1,148
Rate of return on plan assets	(0.50)%	82	—
Rate of increase in compensation	0.50 %	35	267

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 2025 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2025
Health care cost trend rate	0.50 %	$ 6	$ 41
Discount rate	(0.50)%	6	89
Rate of return on plan assets	(0.50)%	12	—

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See Note 2 of the Notes to the Consolidated Financial Statements in Item 8.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2 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,		
	2025	2024	2023
Operating Revenues			
Electric	$ 18,318	$ 17,811	$ 17,424
Natural gas	6,617	6,608	7,004
Total operating revenues	**24,935**	**24,419**	**24,428**
Operating Expenses			
Cost of electricity	2,609	2,261	2,443
Cost of natural gas	1,107	1,192	1,754
Operating and maintenance	11,349	11,808	11,924
SB 901 securitization charges, net	35	33	1,267
Wildfire-related claims, net of recoveries	100	94	64
Wildfire Fund expense	352	383	567
Depreciation, amortization, and decommissioning	4,634	4,189	3,738
Total operating expenses	**20,186**	**19,960**	**21,757**
Operating Income	**4,749**	**4,459**	**2,671**
Interest income	520	604	606
Interest expense	(3,028)	(3,051)	(2,850)
Other income, net	182	300	272
Income Before Income Taxes	**2,423**	**2,312**	**699**
Income tax benefit	(280)	(200)	(1,557)
Net Income	**2,703**	**2,512**	**2,256**
Preferred stock dividend requirement	110	37	14
Income Available for Common Shareholders	**$ 2,593**	**$ 2,475**	**$ 2,242**
Weighted Average Common Shares Outstanding, Basic	**2,197**	**2,141**	**2,064**
Weighted Average Common Shares Outstanding, Diluted	**2,202**	**2,147**	**2,138**
Net Income Per Common Share, Basic	**$ 1.18**	**$ 1.16**	**$ 1.09**
Net Income Per Common Share, Diluted	**$ 1.18**	**$ 1.15**	**$ 1.05**

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2025	**2024**	**2023**
Net Income	**$ 2,703**	**$ 2,512**	**$ 2,256**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $4, $3, and $6, respectively)	(11)	(7)	(16)
Net unrealized gain (losses) on available-for-sale securities (net of taxes of $2, $0, and $3, respectively)	5	1	8
Total other comprehensive income (loss)	**(6)**	**(6)**	**(8)**
Comprehensive Income	**2,697**	**2,506**	**2,248**
Preferred stock dividend requirement	**110**	**37**	**14**
Comprehensive Income Attributable to Common Shareholders	**$ 2,587**	**$ 2,469**	**$ 2,234**

See accompanying Notes to the Consolidated Financial Statements.

PG&E CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at	
	December 31, 2025	**December 31, 2024**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 713	$ 940
Restricted cash and restricted cash equivalents (includes $225 million and $263 million related to VIEs at respective dates)	259	273
Accounts receivable		
Customers (net of allowance for doubtful accounts of $408 million and $418 million at respective dates) (includes $1.9 billion related to VIEs, net of allowance for doubtful accounts of $408 million and $418 million at respective dates)	2,267	2,220
Accrued unbilled revenue (includes $1.3 billion related to VIEs at respective dates)	1,463	1,487
Regulatory balancing accounts	6,300	7,227
Other (net of allowance for doubtful accounts of $69 million and $35 million at respective dates)	1,719	1,810
Regulatory assets	305	234
Inventories		
Gas stored underground and fuel oil	75	52
Materials and supplies	745	768
Wildfire Fund asset	297	301
Wildfire self-insurance asset	1,043	905
Other	644	999
Total current assets	**15,830**	**17,216**
Property, Plant, and Equipment		
Property, Plant, and Equipment	128,989	118,262
Construction work in progress	4,627	4,458
Financing lease ROU asset and other	2	814
Total property, plant, and equipment	**133,618**	**123,534**
Accumulated depreciation	(37,270)	(35,305)
Net property, plant, and equipment	**96,348**	**88,229**
Other Noncurrent Assets		
Regulatory assets	15,981	15,561
Customer credit trust	804	377
Nuclear decommissioning trusts	4,230	3,833
Operating lease ROU asset	450	524
Wildfire Fund asset	3,728	4,070
Other (includes noncurrent accounts receivable of $67 million and $82 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $18 at respective dates)	4,240	3,850
Total other noncurrent assets	**29,433**	**28,215**
TOTAL ASSETS	**$ 141,611**	**$ 133,660**

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at	
	December 31, 2025	**December 31, 2024**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,675	$ 1,523
Long-term debt, classified as current (includes $221 million and $222 million related to VIEs at respective dates)	821	2,146
Accounts payable		
Trade creditors	3,353	2,748
Regulatory balancing accounts	3,119	3,169
Other	929	748
Operating lease liabilities	90	85
Financing lease liabilities	—	577
Interest payable (includes $72 million and $91 million related to VIEs at respective dates)	764	760
Wildfire-related claims	524	916
Other	4,025	3,658
Total current liabilities	**16,300**	**16,330**
Noncurrent Liabilities		
Long-term debt (includes $11.7 billion and $10.1 billion related to VIEs at respective dates)	57,387	53,569
Regulatory liabilities	20,188	19,417
Pension and other postretirement benefits	549	808
Asset retirement obligations	5,439	5,444
Deferred income taxes	4,135	3,082
Operating lease liabilities	360	439
Financing lease liabilities	2	4
Other	4,459	4,166
Total noncurrent liabilities	**92,519**	**86,929**
Equity		
Shareholders' Equity		
Mandatory convertible preferred stock	1,579	1,579
Common stock, no par value, authorized 3,600,000,000 and 3,600,000,000 shares at respective dates; 2,197,942,874 and 2,193,573,536 shares outstanding at respective dates	31,636	31,555
Reinvested earnings	(650)	(2,966)
Accumulated other comprehensive loss	(25)	(19)
Total shareholders' equity	**32,540**	**30,149**
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	**32,792**	**30,401**
TOTAL LIABILITIES AND EQUITY	**$ 141,611**	**$ 133,660**

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2025	**2024**	**2023**
Cash Flows from Operating Activities			
Net income	$ 2,703	$ 2,512	$ 2,256
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	4,634	4,189	3,738
Bad debt expense	402	341	636
Allowance for equity funds used during construction	(219)	(184)	(179)
Deferred income taxes and tax credits, net	1,058	1,098	(765)
Wildfire Fund expense	352	383	568
Other	(75)	310	(116)
Effect of changes in operating assets and liabilities:			
Accounts receivable	(61)	(1,061)	(369)
Wildfire-related insurance receivable	(167)	318	358
Inventories	—	45	(28)
Accounts payable	176	30	(90)
Wildfire-related claims	(392)	(506)	(489)
Other current assets and liabilities	563	(231)	397
Regulatory assets, liabilities, and balancing accounts, net	173	1,545	(429)
Contributions to Wildfire Fund	(193)	(193)	(193)
Other noncurrent assets and liabilities	(238)	(561)	(548)
Net cash provided by operating activities	**8,716**	**8,035**	**4,747**
Cash Flows from Investing Activities			
Capital expenditures	(11,787)	(10,369)	(9,714)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,952	1,980	2,235
Purchases of nuclear decommissioning trust investments	(1,993)	(2,002)	(2,252)
Proceeds from sales and maturities of customer credit trust investments	435	398	556
Purchases of customer credit trust investments	(742)	(519)	—
Proceeds from sales and maturities of self-insurance investments	1,181	—	—
Purchases of self-insurance investments	(1,384)	(898)	—
Other	22	35	13
Net cash used in investing activities	**(12,316)**	**(11,375)**	**(9,162)**
Cash Flows from Financing Activities			
Borrowings under credit facilities	4,790	6,873	10,675
Repayments under credit facilities	(1,465)	(10,122)	(10,540)
Borrowings under term loan	575	—	2,100
Repayments under term loan	—	(2,600)	(2,181)
Short-term debt financing, net of issuance costs of $0, $1, and $0 at respective dates	—	999	—
Short-term debt matured	(1,000)	—	—
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $38, $5, and $67 at respective dates	4,962	4,495	5,483
Repayment of long-term debt	(3,876)	(800)	(3,075)

Proceeds from issuance of AB 1054 recovery bonds, net of financing fees of $0, $10 and $0 at respective dates	—	1,409	—
Repayment of AB 1054 recovery bonds	(88)	(46)	(38)
Repayment of SB 901 recovery bonds	(135)	(129)	(130)
Proceeds from DWR loan	—	980	—
Proceeds from issuance of convertible notes, net of discount and issuance costs of $0, $0, and $27 at respective dates	—	—	2,123
Common stock issued	—	1,128	—
Mandatory convertible preferred stock issued	—	1,579	—
Common stock dividends paid	(220)	(86)	—
Mandatory convertible preferred stock dividends paid	(97)	—	—
Other	(87)	(59)	(17)
Net cash provided by financing activities	**3,359**	**3,621**	**4,400**
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**(241)**	**281**	**(15)**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at January 1	**1,213**	**932**	**947**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at December 31	**$ 972**	**$ 1,213**	**$ 932**
Less: Restricted cash and restricted cash equivalents	(259)	(273)	(297)
Cash and cash equivalents at December 31	**$ 713**	**$ 940**	**$ 635**
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest, net of amounts capitalized	$ (2,665)	$ (2,421)	$ (2,286)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$ 1,859	$ 1,144	$ 1,105
Operating lease liabilities arising from obtaining ROU assets	—	6	269
Financing lease liabilities arising from obtaining ROU assets	—	43	52
Reclassification of operating lease liabilities to financing lease liabilities	—	—	913
DWR loan forgiveness and performance-based disbursements	148	192	214
Changes to PG&E Corporation common stock and treasury stock in connection with share exchanges with the Fire Victim Trust	—	—	(2,517)
Common stock dividends declared but not yet paid	111	55	21
Mandatory convertible preferred stock dividends declared but not yet paid	23	23	—
Capital expenditures financed through current assets and non-current liabilities	592	—	—

See accompanying Notes to the Consolidated Financial Statements.

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

	Preferred Stock	Common Stock		Treasury Stock		Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non-controlling Interest - Preferred Stock of Subsidiary	Total Equity
		Shares	Amount	Shares	Amount					
Balance at December 31, 2022	**$ —**	**1,987,784,948**	**$ 32,887**	**247,743,590**	**$ (2,517)**	**$ (7,542)**	**$ (5)**	**$ 22,823**	**$ 252**	**$ 23,075**
Net income	—	—	—	—	—	2,256	—	2,256	—	2,256
Other comprehensive loss	—	—	—	—	—	—	(8)	(8)	—	(8)
Common stock issued, net	—	145,812,810	(2,517)	—	—	—	—	(2,517)	—	(2,517)
Treasury stock disposition	—	—	—	(247,743,590)	2,517	—	—	2,517	—	2,517
Stock-based compensation amortization	—	—	4	—	—	—	—	4	—	4
Common stock dividends declared	—	—	—	—	—	(21)	—	(21)	—	(21)
Preferred stock dividend requirement of subsidiary	—	—	—	—	—	(14)	—	(14)	—	(14)
Balance at December 31, 2023	**$ —**	**2,133,597,758**	**$ 30,374**	**—**	**$ —**	**$ (5,321)**	**$ (13)**	**$ 25,040**	**$ 252**	**$ 25,292**
Net income	—	—	—	—	—	2,512	—	2,512	—	2,512
Other comprehensive loss	—	—	—	—	—	—	(6)	(6)	—	(6)
Preferred Stock issued, net	1,579	—	—	—	—	—	—	1,579	—	1,579
Common stock issued, net	—	59,975,778	1,128	—	—	—	—	1,128	—	1,128
Stock-based compensation amortization	—	—	53	—	—	—	—	53	—	53
Common stock dividends declared	—	—	—	—	—	(120)	—	(120)	—	(120)
Preferred stock dividend requirement	—	—	—	—	—	(37)	—	(37)	—	(37)
Balance at December 31, 2024	**$ 1,579**	**2,193,573,536**	**$ 31,555**	**—**	**$ —**	**$ (2,966)**	**$ (19)**	**$ 30,149**	**$ 252**	**$ 30,401**
Net income	—	—	—	—	—	2,703	—	2,703	—	2,703
Other comprehensive loss	—	—	—	—	—	—	(6)	(6)	—	(6)
Common stock issued, net	—	4,369,338	(1)	—	—	—	—	(1)	—	(1)
Stock-based compensation amortization	—	—	82	—	—	—	—	82	—	82
Common stock dividends declared	—	—	—	—	—	(277)	—	(277)	—	(277)
Preferred stock dividend requirement	—	—	—	—	—	(110)	—	(110)	—	(110)
Balance at December 31, 2025	**$ 1,579**	**2,197,942,874**	**$ 31,636**	**—**	**$ —**	**$ (650)**	**$ (25)**	**$ 32,540**	**$ 252**	**$ 32,792**

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2025	**2024**	**2023**
Operating Revenues			
Electric	$ 18,318	$ 17,811	$ 17,424
Natural gas	6,617	6,608	7,004
Total operating revenues	**24,935**	**24,419**	**24,428**
Operating Expenses			
Cost of electricity	2,609	2,261	2,443
Cost of natural gas	1,107	1,192	1,754
Operating and maintenance	11,337	11,787	11,913
SB 901 securitization charges, net	35	33	1,267
Wildfire-related claims, net of recoveries	100	94	64
Wildfire Fund expense	352	383	567
Depreciation, amortization, and decommissioning	4,634	4,189	3,738
Total operating expenses	**20,174**	**19,939**	**21,746**
Operating Income	**4,761**	**4,480**	**2,682**
Interest income	509	589	593
Interest expense	(2,713)	(2,781)	(2,485)
Other income, net	328	319	293
Income Before Income Taxes	**2,885**	**2,607**	**1,083**
Income tax benefit	(194)	(105)	(1,461)
Net Income	**3,079**	**2,712**	**2,544**
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	**$ 3,065**	**$ 2,698**	**$ 2,530**

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2025	**2024**	**2023**
Net Income	**$ 3,079**	**$ 2,712**	**$ 2,544**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $4, $3, and $$5, respectively)	(8)	(8)	(12)
Net unrealized gain (losses) on available-for-sale securities (net of taxes of $2, $0, and $4, respectively)	5	1	7
Total other comprehensive income (loss)	**(3)**	**(7)**	**(5)**
Comprehensive Income	**$ 3,076**	**$ 2,705**	**$ 2,539**

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at	
	December 31, 2025	**December 31, 2024**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 353	$ 705
Restricted cash and restricted cash equivalents (includes $225 million and $263 million related to VIEs at respective dates)	258	272
Accounts receivable		
Customers (net of allowance for doubtful accounts of $408 million and $418 million at respective dates) (includes $1.9 billion related to VIEs, net of allowance for doubtful accounts of $408 million and $418 million at respective dates)	2,267	2,220
Accrued unbilled revenue (includes $1.3 billion related to VIEs at respective dates)	1,463	1,487
Regulatory balancing accounts	6,300	7,227
Other (net of allowance for doubtful accounts of $69 million and $35 million at respective dates)	1,725	1,810
Regulatory assets	305	234
Inventories		
Gas stored underground and fuel oil	75	52
Materials and supplies	745	768
Wildfire Fund asset	297	301
Wildfire self-insurance asset	1,043	905
Other	643	998
Total current assets	**15,474**	**16,979**
Property, Plant, and Equipment		
Property, Plant, and Equipment	128,989	118,262
Construction work in progress	4,626	4,458
Financing lease ROU asset and other	2	814
Total property, plant, and equipment	**133,617**	**123,534**
Accumulated depreciation	(37,269)	(35,304)
Net property, plant, and equipment	**96,348**	**88,230**
Other Noncurrent Assets		
Regulatory assets	15,981	15,561
Customer credit trust	804	377
Nuclear decommissioning trusts	4,230	3,833
Operating lease ROU asset	445	519
Wildfire Fund asset	3,728	4,070
Other (includes noncurrent accounts receivable of $67 million and $82 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $18 at respective dates)	4,073	3,697
Total other noncurrent assets	**29,261**	**28,057**
TOTAL ASSETS	**$ 141,083**	**$ 133,266**

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, 2025	**December 31, 2024**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 2,675	$ 1,523
Long-term debt, classified as current (includes $221 million and $222 million related to VIEs at respective dates)	821	2,146
Accounts payable		
Trade creditors	3,352	2,745
Regulatory balancing accounts	3,119	3,169
Other	844	729
Operating lease liabilities	90	85
Financing lease liabilities	—	577
Interest payable (includes $72 million and $91 million related to VIEs at respective dates)	673	667
Wildfire-related claims	524	916
Other	3,710	3,331
Total current liabilities	**15,808**	**15,888**
Noncurrent Liabilities		
Long-term debt (includes $11.7 billion and $10.1 billion related to VIEs at respective dates)	51,766	47,958
Regulatory liabilities	20,188	19,417
Pension and other postretirement benefits	482	741
Asset retirement obligations	5,439	5,444
Deferred income taxes	4,732	3,632
Operating lease liabilities	355	434
Financing lease liabilities	2	4
Other	4,474	4,198
Total noncurrent liabilities	**87,438**	**81,828**
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 800,000,000 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	37,505	35,930
Reinvested earnings	(1,225)	(1,940)
Accumulated other comprehensive loss	(23)	(20)
Total shareholders' equity	**37,837**	**35,550**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 141,083**	**$ 133,266**

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2025	**2024**	**2023**
Cash Flows from Operating Activities			
Net income	$ 3,079	$ 2,712	$ 2,544
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	4,634	4,189	3,738
Bad debt expense	402	341	636
Allowance for equity funds used during construction	(219)	(184)	(179)
Deferred income taxes and tax credits, net	1,102	1,195	(663)
Wildfire Fund expense	352	383	568
Other	(158)	233	(176)
Effect of changes in operating assets and liabilities:			
Accounts receivable	(67)	(1,060)	(361)
Wildfire-related insurance receivable	(167)	318	358
Inventories	—	45	(28)
Accounts payable	112	44	(90)
Wildfire-related claims	(392)	(506)	(489)
Other current assets and liabilities	617	(235)	402
Regulatory assets, liabilities, and balancing accounts, net	173	1,545	(429)
Contributions to Wildfire Fund	(193)	(193)	(193)
Other noncurrent assets and liabilities	(240)	(559)	(541)
Net cash provided by operating activities	**9,035**	**8,268**	**5,097**
Cash Flows from Investing Activities			
Capital expenditures	(11,787)	(10,369)	(9,714)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,952	1,980	2,235
Purchases of nuclear decommissioning trust investments	(1,993)	(2,002)	(2,252)
Proceeds from sales and maturities of customer credit trust investments	435	398	556
Purchases of customer credit investments	(742)	(519)	—
Proceeds from sales and maturities of self-insurance investments	1,181	—	—
Purchases of self-insurance investments	(1,384)	(898)	—
Other	22	35	13
Net cash used in investing activities	**(12,316)**	**(11,375)**	**(9,162)**
Cash Flows from Financing Activities			
Borrowings under credit facilities	4,790	6,873	10,675
Repayments under credit facilities	(1,465)	(10,122)	(10,540)
Borrowings under term loan	575	—	2,100
Repayments under term loan	—	(2,100)	—
Short-term debt financing, net of issuance costs of $0, $1, and $0 at respective dates	—	999	—
Short-term debt matured	(1,000)	—	—
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $38, $1, and $67 at respective dates	4,962	2,999	5,483
Repayment of long-term debt	(3,876)	(800)	(3,075)

Proceeds from AB 1054 recovery bonds, net issuance costs of $0, $10, and $0 at respective dates	—	1,409	—
Repayment of AB 1054 recovery bonds	(88)	(46)	(38)
Repayment of SB 901 recovery bonds	(135)	(129)	(130)
Proceeds from DWR loan	—	980	—
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(2,350)	(2,025)	(1,775)
Equity contribution from PG&E Corporation	1,575	5,360	1,290
Other	(59)	(36)	3
Net cash provided by financing activities	**2,915**	**3,348**	**3,979**
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**(366)**	**241**	**(86)**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at January 1	**977**	**736**	**822**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at December 31	**$ 611**	**$ 977**	**$ 736**
Less: Restricted cash and restricted cash equivalents	(258)	(272)	(294)
Cash and cash equivalents at December 31	**$ 353**	**$ 705**	**$ 442**

Supplemental disclosures of cash flow information			
Cash paid for:			
Interest, net of amounts capitalized	$ (2,359)	$ (2,206)	$ (1,977)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$ 1,859	$ 1,144	$ 1,105
Operating lease liabilities arising from obtaining ROU assets	—	1	269
Financing lease liabilities arising from obtaining ROU assets	—	43	52
Reclassification of operating lease liabilities to financing lease liabilities	—	—	913
DWR loan forgiveness and performance-based disbursements	148	192	214
Capital expenditures financed through current assets and non-current liabilities	592	—	—

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, 2022	**$ 258**	**$ 1,322**	**$ 29,280**	**$ (3,368)**	**$ (8)**	**$ 27,484**
Net income	—	—	—	2,544	—	2,544
Other comprehensive loss	—	—	—	—	(5)	(5)
Equity contribution	—	—	1,290	—	—	1,290
Preferred stock dividend requirement	—	—	—	(14)	—	(14)
Common stock dividend	—	—	—	(1,775)	—	(1,775)
Balance at December 31, 2023	**$ 258**	**$ 1,322**	**$ 30,570**	**$ (2,613)**	**$ (13)**	**$ 29,524**
Net income	—	—	—	2,712	—	2,712
Other comprehensive loss	—	—	—	—	(7)	(7)
Equity contribution	—	—	5,360	—	—	5,360
Preferred stock dividend requirement	—	—	—	(14)	—	(14)
Common stock dividend	—	—	—	(2,025)	—	(2,025)
Balance at December 31, 2024	**$ 258**	**$ 1,322**	**$ 35,930**	**$ (1,940)**	**$ (20)**	**$ 35,550**
Net income	—	—	—	3,079	—	3,079
Other comprehensive loss	—	—	—	—	(3)	(3)
Equity contribution	—	—	1,575	—	—	1,575
Preferred stock dividend requirement	—	—	—	(14)	—	(14)
Common stock dividend	—	—	—	(2,350)	—	(2,350)
Balance at December 31, 2025	**$ 258**	**$ 1,322**	**$ 37,505**	**$ (1,225)**	**$ (23)**	**$ 37,837**

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: 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.

Segment Reporting

PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis and operate as one reportable segment. PG&E Corporation's and the Utility's chief operating decision maker is the Chief Executive Officer of PG&E Corporation.

Net income (loss) is the measure that the chief operating decision maker uses to assess performance and decide how to allocate resources and that is most consistent with GAAP principles. Net income is reported on PG&E Corporation's Consolidated Statements of Income. Because PG&E Corporation and the Utility are a single reportable segment, all segment financial information can be found in PG&E Corporation's Consolidated Financial Statements.

PG&E Corporation and the Utility do not have any significant segment expenses because the chief operating decision maker is not regularly provided with information that is considered to be significant under ASC 280, Segment Reporting. Except for publicly available information, the information regularly provided to the chief operating decision maker consists of financial reports with metrics that combine year-to-date actual results with forecasts of the remainder of the year in order to provide a comprehensive view of the entire year. These metrics do not separate expenses already incurred from forecast information.

Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents

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, 2025 and 2024, the Utility also held $258 million and $272 million of Restricted cash and restricted cash equivalents, respectively, that primarily consist of AB 1054 and SB 901 fixed recovery charge collections that are to be used to service the associated bonds.

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. CPUC and FERC rates decouple authorized revenue from the volume of electricity and natural gas sales, so the Utility receives revenue equal to the amounts authorized by the relevant regulatory agencies. As a result, the volume of electricity and natural gas sold does not have a direct impact on PG&E Corporation's and the Utility's financial results. 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 through 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 December 31,		
(in millions)	**2025**	**2024**	**2023**
Electric			
Revenue from contracts with customers			
Residential	$ 6,976	$ 7,504	$ 6,041
Commercial	7,022	7,201	5,643
Industrial	1,929	2,065	1,784
Agricultural	1,825	1,815	1,413
Public street and highway lighting	105	103	83
Other, net [1]	72	(47)	136
Total revenue from contracts with customers - electric	17,929	18,641	15,100
Regulatory balancing accounts [2]	389	(830)	2,324
Total electric operating revenue	**$ 18,318**	**$ 17,811**	**$ 17,424**
Natural gas			
Revenue from contracts with customers			
Residential	$ 3,651	$ 3,089	$ 3,686
Commercial	1,074	984	1,052
Transportation service only	1,937	1,815	1,603
Other, net [1]	101	159	(145)
Total revenue from contracts with customers - gas	6,763	6,047	6,196
Regulatory balancing accounts [2]	(146)	561	808
Total natural gas operating revenue	**6,617**	**6,608**	**7,004**
Total operating revenues	**$ 24,935**	**$ 24,419**	**$ 24,428**

[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 alternative 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, 2025, 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.

Expected credit losses of $402 million, $341 million, and $636 million were recorded in Operating and maintenance expense on the Consolidated Statements of Income for credit losses associated with trade and other receivables during the years ended December 31, 2025, 2024, and 2023, respectively. The portion of expected credit losses that are deemed probable of recovery are deferred to the RUBA and a FERC regulatory asset account. As of December 31, 2025, the RUBA current balancing accounts and FERC noncurrent regulatory asset balances were $278 million and $92 million, respectively. As of December 31, 2024, the RUBA current balancing accounts and FERC noncurrent regulatory asset balances were $260 million and $85 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. For more information, see Note 14 below. Wildfire Fund receivables risk is related to the Wildfire Fund's durability, which is a measurement of its claim-paying capacity. For certain investments held by PG&E Corporation and the Utility, the companies are required to determine if the fair value is below the amortized cost basis for their available-for-sale debt securities (i.e., impairment). If such an impairment exists and does not otherwise result in a write-down, 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, 2025, expected credit losses for insurance receivables, Wildfire Fund receivables, and available-for-sale debt securities were immaterial.

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.

Inventories

Inventories are carried at weighted-average cost and include gas stored underground, fuel oil, 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 for use 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.

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 allowance for funds used during construction ("AFUDC"). See "Allowance for Funds Used During Construction" below. The Utility's estimated service lives of its property, plant, and equipment were as follows:

	Estimated Service	Balance at December 31,	
(in millions, except estimated service lives)	**Lives (years)**	**2025**	**2024**
Electricity generating facilities [1]	1 to 75	$ 11,986	$ 11,420
Electricity distribution facilities	5 to 70	57,174	49,821
Electricity transmission facilities	5 to 80	20,959	18,481
Natural gas distribution facilities	15 to 60	18,240	17,213
Natural gas transmission and storage facilities	15 to 68	11,315	11,117
General plant and other	5 to 50	9,315	10,210
Financing lease		2	814
Construction work in progress		4,626	4,458
Total property, plant, and equipment		**133,617**	**123,534**
Accumulated depreciation		(37,269)	(35,304)
Net property, plant, and equipment [2]		**$ 96,348**	**$ 88,230**

(1) Balance includes nuclear fuel inventories, which are stated at weighted-average cost. See Note 15 below. Nuclear generating facilities have been fully depreciated by December 31, 2025.
(2) Includes $2.9 billion of fire risk mitigation-related property, plant, and equipment securitized in accordance with AB 1054.

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 in 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 3.77% in 2025 and 3.61% in 2024. 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 asset 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.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost 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 $88 million and $219 million during 2025, $111 million and $184 million during 2024, and $82 million and $179 million during 2023.

Asset Retirement Obligations

The following table summarizes the changes in ARO during 2025 and 2024, including nuclear decommissioning obligations:

(in millions)	**2025**	**2024**
ARO liability at beginning of year	$ 5,444	$ 5,512
Revision in estimated cash flows	(274)	(290)
Accretion	290	269
Liabilities settled	(21)	(47)
ARO liability at end of year	**$ 5,439**	**$ 5,444**

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. For more information, see Note 3 below.

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; removal of hazardous materials in some gas transmission assets and restoration of land to the conditions under certain agreements.

The total nuclear decommissioning obligation was $4.2 billion as of December 31, 2025 and $4.0 billion as of December 31, 2024 based on the cost study performed as part of the 2021 NDCTP. The Utility's ARO assumes that DCPP operates until 2030. The ARO could be materially impacted if the Utility does not receive the required federal and state licenses, permits, and approvals.

Disallowance of Plant Costs

PG&E Corporation and the Utility recognizes a loss 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 DCPP and the Humboldt Bay independent spent fuel storage installation. 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 cost of debt and equity securities sold by the trust is determined by specific identification. Gains on the nuclear decommissioning trust investments are refundable to customers through rates, and losses are recoverable 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.

Government Assistance

The Utility participated in various government assistance programs during the year ended December 31, 2025, 2024, and 2023. The Utility accounts for government grants in accordance with ASU 2025-10, *Government Grants (Topic 832).*

Assembly Bill 180

On June 30, 2022, AB 180 became law. AB 180 authorized the DWR to use up to $75 million to support contracts with the owners of electric generating facilities pending retirement, such as DCPP, to fund, reimburse or compensate the owner for any costs, expenses or financial commitments incurred to retain the future availability of such generating facilities pending further legislation. The resulting agreement between DWR and the Utility was effective beginning October 1, 2022, and will continue until full disbursement of funds or termination per the agreement. In the event of a termination, the Utility will take reasonable steps to end activities associated with this agreement and will return to DWR any unused funds. During the year ended December 31, 2025, the Consolidated Statements of Income reflected $13 million, as a deduction to Cost of electricity for income related to government grants for incurred eligible costs to purchase nuclear fuel. During the year ended December 31, 2024, the amount recorded as a reduction to Cost of electricity for income related to government grants for incurred eligible costs to purchase nuclear fuel was immaterial to the Consolidated Statements of Income. During the year ended December 31, 2023, the Consolidated Statements of Income reflected $56 million, as a deduction to Cost of electricity for income related to government grants for incurred eligible costs to purchase nuclear fuel.

DWR Loan Agreement

On October 18, 2022, the DWR and the Utility entered into a $1.4 billion loan agreement to support the extension of DCPP, with up to $1.1 billion potentially repaid by DOE funds. Under the agreement, the Utility received monthly performance-based disbursements of $7 per MWh generated, capped at $300 million. The final proceeds were received in 2024, and no further disbursements will be made.

The Utility initially accounted for all disbursements from the DWR loan agreement pursuant to ASC 470, *Debt*. When the Utility has reasonable assurance that the DWR will forgive loan disbursements (such as when the Utility earns a performance-based disbursement or when funds expected to be received from the DOE are less than incurred eligible costs), the Utility recognizes those forgiven loans as income related to government grants. The Utility records the income related to government grants as a deduction to expense in the same period(s) that eligible costs are incurred.

The following table summarizes where DWR loan activity is presented in PG&E Corporation's and the Utility's Consolidated Financial Statements:

(in millions)	2025	2024	2023
Long-term debt:			
Beginning Balance - DWR loan outstanding	$ 886	$ 98	$ 312
Proceeds received	—	980	—
Operating Expenses:			
Operating and maintenance expense - *Performance-based disbursements*	(21)	(117)	(124)
Operating and maintenance expense - *Loan forgiveness and other adjustments*	(127)	(75)	(90)
Long-term debt:			
Ending Balance - DWR loan outstanding	$ 738	$ 886	$ 98

U.S. DOE's Civil Nuclear Credit Program

On January 11, 2024, the Utility and the DOE entered into a Credit Award and Payment Agreement for up to $1.1 billion related to DCPP as part of the DOE's Civil Nuclear Credit Program. The Utility uses these funds to repay its loans outstanding under the DWR Loan Agreement (see "DWR Loan Agreement" above). Final award amounts are determined following completion of each year of the award period, and amounts awarded over a four-year award period ending in 2026 will be based on a number of factors, including actual costs incurred to extend the DCPP operations. When there is reasonable assurance that the Utility will receive funding and comply with the conditions of the DOE's Civil Nuclear Credit Program, the Utility recognizes such funding as income and records a receivable related to government grants. During the years ended December 31, 2025, 2024, and 2023, the Consolidated Statements of Income reflected $65 million, $265 million, and $115 million, respectively, as a deduction to Operating and maintenance expense, for income related to government grants for incurred eligible costs to support the extension of DCPP. During the years ended December 31, 2025, 2024, and 2023, the Consolidated Statements of Income reflected $69 million, $138 million, and $76 million, respectively, as deductions to Cost of electricity, for income related to government grants for incurred fuel costs to support the extension of DCPP.

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 was created in connection with the Receivables Securitization Program and 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 pledged receivables and the corresponding debt are included in Accounts receivable, Accrued unbilled revenue, Other noncurrent assets, and Long-term debt on the Consolidated Balance Sheets.

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, 2025 or is expected to be provided in the future that was not previously contractually required. As of December 31, 2025 and December 31, 2024, the SPV had net accounts receivable of $3.2 billion, and outstanding borrowings of $1.8 billion and $0 million, respectively, under the Receivables Securitization Program. For more information, see Note 4 below.

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 orders for the AB 1054 securitization transactions, the Utility sold its right to receive revenues from non-bypassable fixed recovery charges ("Recovery Property") to PG&E Recovery Funding LLC, which, in turn, issued three separate series of recovery bonds secured by separate Recovery Property.

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, 2025 or is expected to be provided in the future that was not previously contractually required. Between 2021 and 2024, PG&E Recovery Funding LLC issued an aggregate of $3.26 billion of senior secured recovery bonds. As of December 31, 2025 and December 31, 2024, PG&E Recovery Funding LLC had outstanding borrowings of $3.1 billion and $3.2 billion, respectively, included in Long-term debt and Long-term debt, classified as current on the Consolidated Balance Sheets.

SB 901 Securitization

PG&E Wildfire 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 the first and second SB 901 securitization transactions, the Utility sold its right to receive revenues from non-bypassable fixed recovery charges ("SB 901 Recovery Property") to PG&E Wildfire Recovery Funding LLC, which, in turn, issued two separate series of recovery bonds secured by separate SB 901 Recovery Property.

PG&E Wildfire 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 Wildfire Recovery Funding LLC are decisions made by the servicer of the SB 901 Recovery Property. The Utility is considered the primary beneficiary and consolidates PG&E Wildfire Recovery Funding LLC as it acts in this role as servicer. No additional financial support was provided to PG&E Wildfire Recovery Funding LLC during the year ended December 31, 2025 or is expected to be provided in the future that was not previously contractually required. In 2022, PG&E Wildfire Recovery Funding LLC issued an aggregate $7.5 billion of senior secured recovery bonds. As of December 31, 2025 and December 31, 2024, PG&E Wildfire Recovery Funding LLC had outstanding borrowings of $7.1 billion and $7.2 billion, respectively, included in Long-term debt and Long-term debt, classified as current on the Consolidated Balance Sheets. For more information, see Note 5 below.

Non-Consolidated VIEs

Power Purchase Agreements

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 as of December 31, 2025, the Utility 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 or 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 as of December 31, 2025, it did not consolidate any of them.

Contributions to the Wildfire Fund and the Continuation Account

AB 1054 did not specify a period of coverage for the Wildfire Fund, and so the accounting treatment is subject to significant judgments and estimates. PG&E Corporation and the Utility account for shareholder contributions to the Wildfire Fund by recognizing an asset, amortizing the asset ratably over the life of the fund based on an estimated period of coverage, and accelerating amortization of the asset when it is determined probable and estimable that the Wildfire Fund longevity has declined, as further described below.

In estimating the life of the fund, PG&E Corporation and the Utility use a dataset of historical, publicly available fire-loss data caused by electrical equipment to create Monte Carlo simulations of expected loss. PG&E Corporation's and the Utility's initial estimated life of the fund was 15 years. In 2024, a re-evaluation resulted in the estimated life increasing from 15 to 20 years.

The number of years of historic fire-loss data, the estimated costs to settle wildfire claims for participating electric utilities (including the Utility), the estimated amount of Wildfire Fund claim payments, and the effectiveness of wildfire mitigation efforts by the California electric utility companies are significant assumptions used to estimate the life of the fund. Other assumptions include the CPUC's determinations of whether costs were just and reasonable in cases of electric utility-caused wildfires and amounts required to be reimbursed to the Wildfire Fund, the impacts of climate change, the FERC-allocable portion of loss recovery, and the future transmission and distribution equity rate base growth of participating electric utilities. The estimated life of the fund has a high degree of uncertainty for many of these assumptions, and so subsequent changes could materially impact the remaining estimated life of the fund.

PG&E Corporation and the Utility have an established process to re-evaluate the estimated life of the fund whenever they obtain new significant fire-loss data. PG&E Corporation and the Utility consider significant fire-loss data to include Cal Fire's annual release of the prior year's fire-loss data, internally developed data about wildfires and wildfire conditions in their own service area, and other participating electric utilities' public disclosures of probable and estimable wildfire-related losses in their service area. PG&E Corporation and the Utility are not able to independently verify other utilities' estimates. During each re-evaluation, PG&E Corporation and the Utility update their assumptions and the dataset of historical fire-losses for wildfires caused by electrical equipment, as applicable. Based upon the outcome of the newly run Monte Carlo simulations, PG&E Corporation and the Utility may determine to increase or decrease, as applicable, the estimated life of the fund. PG&E Corporation and the Utility apply adjustments to the estimated life of the fund on a prospective basis.

In addition to estimating the life of the fund, PG&E Corporation and the Utility also assess the Wildfire Fund asset for accelerated amortization when they record or increase a Wildfire Fund receivable or when reliable information becomes publicly available, including when another participating electric utility discloses a Wildfire Fund receivable.

As of December 31, 2025, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $377 million in Other noncurrent liabilities, $297 million in Current assets - Wildfire Fund asset, and $3.7 billion in Noncurrent assets - Wildfire Fund asset in the Consolidated Balance Sheets. During the years ended December 31, 2025 and 2024, the Utility recorded amortization and accretion expense of $352 million and $383 million, respectively. The amortization of the asset, accretion of the liability, and applicable acceleration of the amortization of the asset are reflected in Wildfire Fund expense in the Consolidated Statements of Income.

PG&E Corporation and the Utility expect to begin accounting for the Continuation Account if the Wildfire Fund administrator determines that the Continuation Account is necessary and the CPUC approves the extension of non-bypassable charges to customers.

For more information, see "Wildfire Fund Recoveries under AB 1054 and SB 254" in Note 14 below.

Oakland Headquarters Purchase

On June 3, 2025, the Utility completed the purchase of the legal parcel that contains the Oakland General Office. The purchase price was $906 million, of which the Utility had prepaid a total of $400 million. At closing, the Utility assumed a $172 million noncurrent liability for a property assessment carried by the property and paid an additional $349 million, which was adjusted for closing costs. The cash payment is included within the Capital expenditures line item in PG&E Corporation's and Utility's Consolidated Statements of Cash Flows, and the property assessment and prepayments are included in Supplemental disclosures of noncash investing and financing activities.

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, "Wildfire-Related Contingencies" in Note 14, and "Other Contingencies and Commitments" in Note 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, 2025 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Available-for-Sale Securities[2]	Total
Beginning balance	**$ (35)**	**$ 18**	**$ 3**	**$ (14)**
Other comprehensive income before reclassifications:				
Unrealized loss on investments (net of taxes of $0, $0 and $2, respectively)	—	—	5	5
Unrecognized net actuarial gain (loss) (net of taxes of $84, $25 and $0, respectively)	215	(64)	—	151
Regulatory account transfer (net of taxes of $89, $25 and $0, respectively)	(228)	64	—	(164)
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (credit) (net of taxes of $1, $1 and $0, respectively) [1]	(2)	2	—	—
Amortization of net actuarial (gain) loss (net of taxes of $1, $6 and $0, respectively) [1]	1	(15)	—	(14)
Regulatory account transfer (net of taxes of $1, $5 and $0, respectively) [1]	2	14	—	16
Net current period other comprehensive income	**(12)**	**1**	**5**	**(6)**
Ending balance	**$ (47)**	**$ 19**	**$ 8**	**$ (20)**

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. See Note 12 below for additional details.
[2] Includes amounts related to the customer credit trust and self-insurance.

The changes, net of income tax, in PG&E Corporation's Accumulated other comprehensive income (loss) for the year ended December 31, 2024 consisted of the following:

(in millions, net of income tax)	**Pension Benefits**	**Other Benefits**	**Available-for-Sale Securities**[2]	**Total**
Beginning balance	**$ (28)**	**$ 18**	**$ 2**	**$ (8)**
Other comprehensive income before reclassifications:				
Unrealized gain on investments (net of taxes of $0, $0 and $0, respectively)	—	—	1	1
Unrecognized net actuarial gain (loss) (net of taxes of $104, $11 and $0, respectively)	(268)	29	—	(239)
Regulatory account transfer (net of taxes of $101, $11 and $0, respectively)	260	(29)	—	231
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (credit) (net of taxes of $1, $1 and $0, respectively) [1]	(2)	2	—	—
Amortization of net actuarial (gain) loss (net of taxes of $0, $6 and $0, respectively)[1]	1	(16)	—	(15)
Regulatory account transfer (net of taxes of $1, $5 and $0, respectively) [1]	2	14	—	16
Net current period other comprehensive income (loss)	**(7)**	**—**	**1**	**(6)**
Ending balance	**$ (35)**	**$ 18**	**$ 3**	**$ (14)**

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. See Note 12 below for additional details.
[2] Includes amounts related to the customer credit trust and wildfire self-insurance.

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 it can ascertain an implicit discount rate from the leasing arrangement. 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 as paid in conformity with ratemaking.

Financing Leases

Financing leases are included in financing lease ROU assets and current and noncurrent financing lease liabilities on the Consolidated Balance Sheets. For the years ended December 31, 2025, 2024 and 2023, the Utility made total fixed cash payments of $26 million, $315 million, and $142 million, respectively, for financing leases, which were included in the measurement of financing lease liabilities and are presented 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 financing lease ROU assets and lease liabilities related to the lease of the Oakland General Office, which the Utility purchased on June 3, 2025. See "Oakland Headquarters Purchase" above.

At December 31, 2025 and 2024, the Utility's financing leases had a weighted average remaining lease term of 4.1 years and 0.5 years and a weighted average discount rate of 4.6% and 6.2%, respectively.

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

	Year Ended December 31,		
(in millions)	**2025**	**2024**	**2023**
Financing lease fixed cost:			
Amortization of ROU assets	$ 583	$ 274	$ 115
Interest on lease liabilities	16	42	27
Financing lease variable cost	(1)	9	3
Total financing lease costs	**$ 598**	**$ 325**	**$ 145**

As of December 31, 2025, the Utility's future expected financing lease payments are not material.

Operating Leases

Operating leases are included in operating lease ROU assets and current and noncurrent Operating lease liabilities on the Consolidated Balance Sheets. For the years ended December 31, 2025, 2024, and 2023, the Utility made total cash payments, including fixed and variable, of $1.6 billion, $1.6 billion, and $1.9 billion, respectively, for operating leases which are presented within operating activities on the Consolidated Statement of Cash Flows.

The majority of the Utility's operating lease 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.

At December 31, 2025 and 2024, the Utility's operating leases had a weighted average remaining lease term of 7.1 years and 7.5 years and a weighted average discount rate of 6.6% and 6.5%, respectively.

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

	Year Ended December 31,		
(in millions)	**2025**	**2024**	**2023**
Operating lease fixed cost	$ 115	$ 116	$ 269
Operating lease variable cost	1,487	1,524	1,632
Total operating lease costs	**$ 1,602**	**$ 1,640**	**$ 1,901**

At December 31, 2025, the Utility's future expected operating lease payments were as follows:

(in millions)	**December 31, 2025**
2026	$ 115
2027	112
2028	98
2029	64
2030	34
Thereafter	165
Total lease payments	**588**
Less imputed interest	(143)
Total	**$ 445**

Recently Adopted Accounting Standards

Income Taxes

In December 2023, the FASB issued ASU No. 2023-09*, Income Taxes (Topic 740): Improvements to Income Tax Disclosures,* which amended the existing guidance to enhance the transparency and decision usefulness of income tax disclosures. PG&E Corporation and the Utility have applied enhanced disclosure requirements, including, but not limited to, those with respect to PG&E Corporation and the Utility's income tax rate reconciliation and income taxes paid. This ASU became effective for PG&E Corporation and the Utility on January 1, 2025 and PG&E Corporation and the Utility have applied the enhanced disclosure requirements of ASU 2023-09 on a retrospective basis.

Derivatives and Hedging and Revenue from Contracts with Customers

In September 2025, the FASB issued ASU No. 2025-07, *Derivatives and Hedging (Topic 815) and Revenue from Contracts with Customers (Topic 606*), which amended the existing guidance to (a) reduce the cost and complexity of evaluating whether contracts with features based on the operations or activities of one of the parties to the contract are derivatives, (b) better portray the economics of those contracts in the financial statements, and (c) reduce diversity in practice resulting from the broad application of the current guidance and changing business environment. The amendments also are expected to reduce diversity in practice by clarifying the applicability of Topic 606, Revenue from Contracts with Customers, to share-based noncash consideration from a customer for the transfer of goods or services. PG&E Corporation and the Utility early adopted the ASU as of December 31, 2025. The adoption of this ASU did not have a significant impact on PG&E Corporation and the Utility's Consolidated Financial Statements and related disclosures.

Accounting Standards Issued But Not Yet Adopted

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU No. 2024-03, *Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*, which amended the existing guidance to require disclosure, in the notes to the financial statements, of specified information about certain costs and expenses. This ASU will become effective for PG&E Corporation and the Utility for fiscal years beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Induced Conversions of Convertible Debt Instruments

In November 2024, the FASB issued ASU No. 2024-04, *Debt—Debt with Conversion and Other Options (Subtopic 470-20): Induced Conversions of Convertible Debt Instruments,* which amended the existing guidance by clarifying the requirements for determining whether certain settlements of convertible debt instruments should be accounted for as induced conversions. Under this ASU, to account for a settlement of a convertible debt instrument as an induced conversion, an inducement offer is required to provide the debt holder with, at a minimum, the consideration (in form and amount) issuable under the conversion privileges provided in the terms of the instrument. An entity should assess whether this criterion is satisfied as of the date the inducement offer is accepted by the holder. This ASU will become effective for PG&E Corporation and the Utility for fiscal years beginning after December 15, 2025, and interim reporting periods within those annual reporting periods, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

Intangibles – Goodwill and Other – Internal Use Software

In September 2025, the FASB issued ASU No. 2025-06, *Intangibles—Goodwill and Other— Internal-Use Software (Subtopic 350-40),* which amended the existing guidance to modernize the accounting for software costs that are accounted for under Subtopic 350-40, *Intangibles—Goodwill and Other—Internal-Use Software*. The amendments in this ASU remove all references to prescriptive and sequential software development stages throughout Subtopic 350-40. Therefore, an entity is required to start capitalizing software costs when both of the following occur: (1) management has authorized and committed to funding the software project, and (2) it is probable that the project will be completed, and the software will be used to perform the function. This ASU will become effective for PG&E Corporation and the Utility for fiscal years beginning after December 15, 2027, and interim reporting periods within those annual reporting periods, with early adoption permitted. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

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. The Utility does not earn a return on regulatory assets if the related costs do not accrue interest.

Noncurrent regulatory assets are comprised of the following:

	Balance at December 31,		Recovery Period
(in millions)	**2025**	**2024**	
Pension benefits [1]	$ 400	$ 673	Indefinitely
Environmental compliance costs	1,158	1,172	32 years
Price risk management	100	167	up to 15.5 years
Catastrophic event memorandum account [2]	666	742	Various
Wildfire-related accounts [3]	1,626	1,697	Various
Deferred income taxes [4]	6,157	4,771	Various
Financing costs [5]	202	216	Various
SB 901 securitization [6]	5,089	5,194	27 years
General rate case memorandum accounts [7]	—	95	Various
Other [8]	583	834	Various
Total noncurrent regulatory assets	**$ 15,981**	**$ 15,561**	

[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] Includes costs of responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities.

[3] Represents costs associated with wildfire mitigation and prevention activities and includes the WEMA, FRMMA, WMPMA, WMBA, VMBA and MGMA.

[4] Represents cumulative differences between amounts recognized for ratemaking purposes and expense recognized in accordance with GAAP.

[5] Includes costs associated with long-term debt financing deemed recoverable under ASC 980, *Regulated Operations* more than twelve months from the current date. These costs and their amortization periods are reviewed and approved in the Utility's cost of capital or other regulatory filings.

[6] In connection with the SB 901 securitization, the CPUC authorized the issuance of recovery bonds to finance $7.5 billion of claims associated with the 2017 Northern California wildfires. The balance represents PG&E Wildfire Recovery Funding LLC's right to recover $7.5 billion in wildfire claims costs associated with the 2017 Northern California wildfires, partially offset by the $2.0 billion in required upfront shareholder contributions to the customer credit trust, net of amortization since inception. The recovery bonds will be paid through fixed recovery charges, which are designed to recover the full scheduled principal amount of the recovery bonds along with any associated interest and financing costs. See Note 5 below.

[7] The GRC memorandum accounts track the differences between the revenue requirements in effect on January 1, 2023 and the revenue requirements authorized by the CPUC in the 2023 GRC final decision in December 2023 to be collected over 24 months. The balance as of December 31, 2024 included revenue to be recognized related to gas transmission and storage capital expenditures incurred during the period from 2011 to 2014. This revenue is being recognized over 60 months, which began in August 2022.

[8] The balance as of December 31, 2025 includes revenue to be recognized related to gas transmission and storage capital expenditures incurred during the period from 2011 to 2014.

Regulatory Liabilities

Current Regulatory Liabilities

At December 31, 2025 and 2024, the Utility had current regulatory liabilities of $965 million and $1.2 billion respectively. At December 31, 2025, current regulatory liabilities consisted primarily of billed revenues exceeding FERC TO formula rate revenue requirements. Current regulatory liabilities are included within Current liabilities - Other in the Consolidated Balance Sheets.

Noncurrent Regulatory Liabilities

Noncurrent regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	**2025**	**2024**
Cost of removal obligations [1]	$ 9,488	$ 8,943
Public purpose programs [2]	1,169	1,112
Employee benefit plans [3]	1,043	1,088
Transmission tower wireless licenses [4]	257	306
SFGO sale [5]	—	79
SB 901 securitization [6]	6,010	6,295
Wildfire self-insurance [7]	1,035	804
Other [8]	1,186	790
Total noncurrent regulatory liabilities	**$ 20,188**	**$ 19,417**

(1) Represents the cumulative differences between the recorded costs to remove assets and amounts collected through rates for expected costs to remove assets.
(2) 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.
(3) Represents cumulative differences between incurred costs and amounts collected through rates for post-retirement medical, post-retirement life, and long-term disability plans.
(4) Represents the portion of the net proceeds received from the sale of transmission tower wireless licenses that will be returned to customers through 2042.
(5) Represents the noncurrent portion of the net gain on the sale of the SFGO, which is being distributed to customers over a five-year period that began in 2022.
(6) In connection with the SB 901 securitization, the Utility is required to return up to $7.59 billion of certain shareholder tax benefits to customers via periodic bill credits over the life of the recovery bonds. The balance reflects qualifying shareholder tax benefits that PG&E Corporation is obligated to contribute to the customer credit trust, net of amortization. See Note 5 below.
(7) Represents amounts collected through rates designated for wildfire self-insurance, plus earnings on investments and less operating expenses of wildfire self-insurance. Balance at December 31, 2025 includes amounts collected through both CPUC and FERC rates. Balance at December 31, 2024 includes only amounts collected through CPUC rates. See Note 14 below.
(8) Includes amounts collected through FERC rates designated for wildfire self-insurance at December 31, 2024. See Note 14 below.

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 timing differences between when costs are incurred and customer revenues are collected.

Some regulatory balancing accounts receivable earn interest which is reflected in Interest income in the Consolidated Statements of Income. Some regulatory balancing accounts payable accrue interest which is reflected in Interest expense in the Consolidated Statements of Income. Interest income from balancing accounts receivable was $419 million, $537 million, and $547 million for the years ended December 31, 2025, 2024, and 2023, respectively. Interest expense from balancing accounts payable was $223 million, $323 million, and $257 million for the years ended December 31, 2025, 2024, and 2023, respectively.

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

	Receivable Balance at December 31,	
(in millions)	**2025**	**2024**
Electric distribution [1]	$ 1,465	$ 1,591
Electric transmission [2]	122	117
Gas distribution and transmission [3]	142	387
Energy procurement [4]	2,711	1,066
Public purpose programs [5]	151	162
Wildfire-related accounts [6]	84	979
Insurance premium costs [7]	—	38
Residential uncollectibles balancing accounts [8]	278	260
Catastrophic event memorandum account [9]	181	500
General rate case memorandum accounts [10]	—	1,113
Other	1,166	1,014
Total regulatory balancing accounts receivable	**$ 6,300**	**$ 7,227**

	Payable Balance at December 31,	
(in millions)	**2025**	**2024**
Electric transmission [2]	$ 37	$ 883
Gas distribution and transmission [3]	78	72
Energy procurement [4]	1,502	329
Public purpose programs [5]	472	882
SFGO sale	83	93
Wildfire-related accounts [6]	338	337
Nuclear decommissioning adjustment mechanism [11]	1	23
Other	608	550
Total regulatory balancing accounts payable	**$ 3,119**	**$ 3,169**

(1) The electric distribution accounts track the collection of revenue requirements approved in the GRC and other proceedings.

(2) The electric transmission accounts track recovery of costs related to the transmission of electricity approved in FERC TO rate cases.

(3) The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and other proceedings.

(4) Energy procurement balancing accounts track recovery of costs related to the procurement of electricity and other revenue requirements approved by the CPUC for recovery in procurement-related balancing accounts, including any environmental compliance-related activities.

(5) The Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for CPUC-mandated programs such as energy efficiency.

(6) The wildfire-related accounts track costs associated with wildfire mitigation and prevention activities and includes the FHPMA, WMPMA, WMBA and VMBA.

(7) The insurance premium costs accounts track the current portion of incremental excess liability insurance costs recorded to the Risk Transfer Balancing Account, as authorized in the 2023 GRC.

(8) The RUBA tracks costs associated with customer protections, including higher uncollectible costs related to limits on electric and gas service disconnections for residential customers.

(9) The CEMA tracks costs associated with responding to catastrophic events that have been declared a disaster or state of emergency by competent federal or state authorities which were approved for cost recovery in the 2020 WMCE final decision, 2021 WMCE final decision, 2022 WMCE final decision, and 2023 WMCE final decision.

(10) The GRC memorandum accounts track the difference between the revenue requirements in effect on January 1, 2023 and the revenue requirements authorized by the CPUC in the 2023 GRC final decision in December 2023.

(11) The Nuclear decommissioning adjustment mechanism account tracks the collection of revenue requirements associated with the decommissioning of the Utility’s nuclear facilities which were approved in the 2021 NDCTP final decision.

NOTE 4: DEBT

Credit Facilities and Term Loans

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings and availability under their credit facilities as of December 31, 2025:

(in millions)	Termination Date	Maximum Facility Limit	Loans Outstanding	Letters of Credit Outstanding	Facility Availability
Utility revolving credit facility	June 2030	$ 5,400 (1)	$ (1,575)	$ (639)	$ 3,186
Utility Receivables Securitization Program (2)	June 2027	1,750 (3)	(1,750)	—	— (3)
PG&E Corporation revolving credit facility	June 2028	650	—	—	650
Total credit facilities		**$ 7,800**	**$ (3,325)**	**$ (639)**	**$ 3,836**

(1) Includes a $2.0 billion letter of credit sublimit.

(2) For more information on the Receivables Securitization Program, see "Variable Interest Entities" in Note 2 above.

(3) The amount the Utility may borrow under the Receivables Securitization Program is limited to the lesser of the facility limit and the facility availability. Further, 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.

Utility

On April 11, 2025, the Utility amended its existing $525 million term loan agreement to extend the maturity date to April 10, 2026. The loan bears interest based on the Utility's election of either (1) Term SOFR (plus a 0.10% credit spread adjustment) plus an applicable margin of 1.375% or (2) the alternative base rate plus an applicable margin of 0.375%.

On June 23, 2025, the Utility amended its existing revolving credit agreement to, among other things, (i) extend the maturity date of such agreement to June 21, 2030, (ii) increase the aggregate commitments from $4.4 billion to $5.4 billion and (iii) modify both the interest rate pricing grid and commitment fee pricing grid.

On June 26, 2025, the Utility and the SPV amended the existing $1.5 billion Receivables Securitization Program to, among other things, (i) extend the scheduled termination date from June 26, 2026 to June 25, 2027 and (ii) allow the Utility and the SPV to request an increase to the commitments by an additional aggregate amount of up to $250 million, subject to the satisfaction of certain terms and conditions.

On September 24, 2025, the Utility entered into a Term Loan Credit Agreement, pursuant to which the lenders made available to the Utility term loans in the aggregate principal amount equal to $500 million (the "Term Loan"). The Term Loan bears interest based on the Utility's election of either (1) Term SOFR plus an applicable margin of 1.250% or (2) the alternative base rate plus an applicable margin of 0.250%. The Utility borrowed the entire amount of the Term Loan on September 24, 2025. The Term Loan has a maturity date of September 23, 2026.

On December 19, 2025, the Utility amended its existing $525 million term loan agreement to, among other things, (i) increase the borrowing capacity to $600 million, (ii) extend the maturity date to December 18, 2026 and (iii) revise the interest rate based on the Utility's election of either (1) the Term SOFR plus an applicable margin of 1.250% or (2) the alternative base rate plus an applicable margin of 0.250%.

PG&E Corporation

On June 23, 2025, PG&E Corporation amended its existing revolving credit agreement to, among other things, (i) extend the maturity date of such agreement to June 22, 2028, (ii) increase the aggregate commitments from $500 million to $650 million and (iii) modify both the interest rate pricing grid and commitment fee pricing grid.

Long-Term Debt Issuances and Redemptions

Utility

On February 24, 2025, the Utility completed the sale of (i) $1.0 billion aggregate principal amount of 5.700% First Mortgage Bonds due 2035 and (ii) $750 million aggregate principal amount of 6.150% First Mortgage Bonds due 2055. The Utility used the net proceeds of such issuances for (i) the repayment of all of its $600 million aggregate principal amount of 3.500% First Mortgage Bonds due June 15, 2025, and (ii) the repayment of all of its $450 million aggregate principal amount of 4.950% First Mortgage Bonds due June 8, 2025. The Utility used the remaining net proceeds from the offerings for general corporate purposes.

On June 4, 2025, the Utility completed the sale of (i) $400 million aggregate principal amount of 5.000% First Mortgage Bonds due 2028, and (ii) $850 million aggregate principal amount of 6.000% First Mortgage Bonds due 2035. The Utility used the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount of 3.15% First Mortgage Bonds due January 1, 2026.

On October 2, 2025, the Utility completed the sale of (i) $400 million aggregate principal amount of 5.000% First Mortgage Bonds due 2028, (ii) $850 million aggregate principal amount of 5.050% First Mortgage Bonds due 2032, and (iii) $750 million aggregate principal amount of 6.100% First Mortgage Bonds due 2055. The Utility used the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount of 3.15% First Mortgage Bonds due January 1, 2026. The Utility used the remaining net proceeds from the offerings for general corporate purposes.

Convertible Notes

On December 4, 2023, PG&E Corporation completed the sale of $2.15 billion aggregate principal amount of 4.25% convertible senior secured notes due December 1, 2027 (the "Convertible Notes"). The Convertible Notes bear interest at an annual rate of 4.25% with interest payable semiannually in arrears on June 1 and December 1 of each year, beginning on June 1, 2024. The net proceeds from these offerings were approximately $2.12 billion, after deducting the initial purchasers' discounts and commissions and PG&E Corporation's offering expenses. PG&E Corporation used the net proceeds to prepay $2.15 billion outstanding under its term loan agreement.

The Convertible Notes are governed by an indenture (the "Convertible Notes Indenture"). The Convertible Notes Indenture contains limited covenants, including those restricting PG&E Corporation's ability and certain of PG&E Corporation's subsidiaries' ability to create liens, engage in sale and leaseback transactions or merge or consolidate with another entity.

Prior to the close of business on the business day immediately preceding September 1, 2027, the Convertible Notes will be convertible by means of Combination Settlement (as described below) when the following conditions are met:

- during any calendar quarter commencing after the calendar quarter ending on March 31, 2024, if the last reported sale price of PG&E Corporation's common stock for at least 20 trading days during the period of 30 consecutive trading days ending on, and including the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day;

- during the five consecutive business day period immediately after any 10 consecutive trading day period ("measurement period") in which the trading price per $1,000 principal amount of Convertible Notes, as determined following a request by a holder of Convertible Notes in accordance with the procedures described in the Convertible Notes Indenture, for each trading day of the measurement period was less than 90% of the product of the last reported sale price of PG&E Corporation's common stock and the conversion rate on each such trading day; or

- upon specified distributions and corporate events described in the Convertible Notes Indenture.

On or after September 1, 2027, the Convertible Notes are convertible by means of Combination Settlement (as described below) by holders at any time in whole or in part until the close of business on the business day immediately preceding the maturity date.

On December 8, 2023, PG&E Corporation delivered an irrevocable notice (the "Irrevocable Notice") to the Trustee under the Convertible Notes Indenture to irrevocably fix the Settlement Method upon conversion to Combination Settlement with a Specified Dollar Amount (each as defined in the Convertible Notes Indenture) per $1,000 principal amount of Convertible Notes at or above $1,000 for any conversions of the Convertible Notes occurring subsequent to the delivery of such Irrevocable Notice on December 8, 2023; provided that in no event shall the Specified Dollar Amount per $1,000 principal amount of Convertible Notes be less than $1,000.

The conversion rate for the Convertible Notes is initially 43.146 shares of common stock per $1,000 principal amount of the Convertible Notes (equivalent to an initial conversion price of approximately $23.18 per share of PG&E Corporation common stock). The conversion rate and the corresponding conversion price are subject to adjustment in connection with some events but will not be adjusted for any accrued and unpaid interest. PG&E Corporation may not redeem the Convertible Notes prior to the maturity date.

If PG&E Corporation undergoes a Fundamental Change (other than an Exempted Fundamental Change, each as defined in the Convertible Notes Indenture), subject to certain conditions, holders may require PG&E Corporation to repurchase for cash all or any portion of their Convertible Notes at a repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the Fundamental Change Repurchase Date (as defined in the Convertible Notes Indenture). As of December 31, 2025, none of the conditions allowing holders of the Convertible Notes to convert had been met.

The Convertible Notes are accounted for in accordance with ASC Subtopic 470-20, *Debt with Conversion and Other Options*. Pursuant to ASC Subtopic 470-20, debt with an embedded conversion feature should be accounted for in its entirety as a liability, and no portion of the proceeds from the issuance of the convertible debt instrument should be accounted for as attributable to the conversion feature unless the conversion feature is required to be accounted for separately as an embedded derivative or the conversion feature results in a premium that is subject to the guidance in ASC 470. The Convertible Notes issued are accounted for as a liability with no portion of the proceeds attributable to the conversion options as the conversion feature did not require separate accounting as a derivative, and the Convertible Notes did not involve a premium subject to the guidance in ASC 470.

As of December 31, 2025 and 2024, the Consolidated Financial Statements reflected the net carrying amount of the Convertible Notes of $2.14 billion and $2.13 billion, with unamortized debt issuance costs of $13 million and $20 million, respectively, in Long-term debt. For the years ended December 31, 2025, 2024, and 2023, the Consolidated Statements of Income reflected the total interest expense of approximately $91 million, $98 million, and $7 million, respectively.

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

		Balance at	
(in millions)	**Contractual Interest Rates**	**December 31, 2025**	**December 31, 2024**
PG&E Corporation			
Convertible Notes due 2027	4.25%	$ 2,150	$ 2,150
Senior Secured Notes due 2028	5.00%	1,000	1,000
Senior Secured Notes due 2030	5.25%	1,000	1,000
Junior Subordinated Notes due 2055	7.38%	1,500	1,500
Unamortized discount, premium and debt issuance costs, net		(29)	(39)
Total PG&E Corporation Long-Term Debt		**5,621**	**5,611**
Utility			
First Mortgage Bonds - Stated Maturity:			
2025	3.45% - 4.95%	—	1,925
2026	2.95%	600	2,551
2027	2.10% - 5.45%	3,000	3,000
2028	3.00% - 5.00%	2,775	1,975
2029	4.20% - 6.10%	2,100	2,100
2030	4.55%	3,100	3,100
2031	2.50% - 3.25%	3,000	3,000
2032	4.40% - 5.90%	1,900	1,050
2033	6.15% - 6.40%	1,900	1,900
2034	5.80% - 6.95%	1,900	1,900
2035	5.70% - 6.00%	1,850	—
2040	3.30% - 4.50%	2,951	2,951
2041	4.20% - 4.50%	700	700
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
2052	5.25%	550	550
2053	6.70% - 6.75%	2,300	2,300
2054	5.90%	750	750
2055	6.10% - 6.15%	1,500	—
Less: current portion, net of unamortized discount and debt issuance costs		(600)	(1,924)
Unamortized discount, premium and debt issuance costs, net		(247)	(226)
Total Utility First Mortgage Bonds		**39,354**	**36,927**
Recovery Bonds [(1)]		10,145	10,367
Less: current portion		(221)	(222)
DWR Loan [(2)]		738	886
Credit Facilities			
Receivables Securitization Program - Stated Maturity: 2027	variable rate [(3)]	1,750	—
Total Utility Long-Term Debt		**51,766**	**47,958**
Total PG&E Corporation Consolidated Long-Term Debt		**$ 57,387**	**$ 53,569**

(1) The amount includes bonds related to AB 1054 and SB 901 securitization transactions. For AB 1054 interest rates, see the 2021 Form 10-K, the 2022 Form 10-K, and the 2024 Form 10-K. For SB 901 interest rates, see the 2022 Form 10-K.

(2) The Utility is not required to pay interest on the DWR loan, see Note 2 - Government Assistance.

(3) At December 31, 2025, the contractual SOFR-based interest rate on the Receivables Securitization Program was 5.31%.

Contractual Repayment Schedule

PG&E Corporation's and the Utility's combined stated long-term debt principal repayment amounts at December 31, 2025 are reflected in the table below:

(in millions, except interest rates)	2026	2027	2028	2029	2030	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	— %	4.25 %	5.00 %	— %	5.25 %	7.38 %	5.39 %
Fixed rate obligations	$ —	$ 2,150	$ 1,000	$ —	$ 1,000	$ 1,500	$ 5,650
Utility [1]							
Average fixed interest rate	2.95 %	3.22 %	3.99 %	5.52 %	4.55 %	4.90 %	4.69 %
Fixed rate obligations	$ 600	$ 3,000	$ 2,775	$ 2,100	$ 3,100	$ 28,626	$ 40,201
Variable interest rate as of December 31, 2025	— %	5.31 %	— %	— %	— %	— %	5.31 %
Variable rate obligations	$ —	$ 1,750	$ —	$ —	$ —	$ —	$ 1,750
Recovery Bonds [2]							
AB 1054 obligations	$ 81	$ 84	$ 88	$ 91	$ 95	$ 2,633	$ 3,072
SB 901 obligations	140	146	152	159	165	6,311	7,073
Total consolidated debt	**$ 821**	**$ 7,130**	**$ 4,015**	**$ 2,350**	**$ 4,360**	**$ 39,070**	**$ 57,746**

[1] The balance excludes the DWR loan, see Note 2 - Government Assistance.
[2] Recovery bonds were issued by, and are repayment obligations of, consolidated VIEs. For AB 1054 interest rates, see the 2021 Form 10-K, the 2022 Form 10-K, and the 2024 Form 10-K. For SB 901 interest rates, see the 2022 Form 10-K.

NOTE 5: SB 901 SECURITIZATION AND CUSTOMER CREDIT TRUST

Pursuant to the financing order for the SB 901 securitization transactions, the Utility sold its right to receive revenues from the SB 901 Recovery Property to PG&E Wildfire Recovery Funding LLC, which, in turn, issued the recovery bonds secured by separate fixed recovery charges and separate SB 901 Recovery Property. The fixed recovery charges are designed to recover the full scheduled principal amount of the applicable series of recovery bonds along with any associated interest and financing costs. The customer credit trust (see Note 11 below) funds a customer credit to ratepayers, designed to equal the recovery bond principal, interest, and financing costs over the life of the recovery bonds to offset the fixed recovery charge. The fixed recovery charges and customer credits are presented on a net basis in Operating revenues in the Consolidated Statements of Income and had no net impact on Operating revenues for the year ended December 31, 2025.

Upon issuance of senior secured recovery bonds in May 2022 ("inception"), the Utility recorded a $5.5 billion SB 901 securitization regulatory asset reflecting PG&E Wildfire Recovery Funding LLC's right to recover $7.5 billion in wildfire claims costs associated with the 2017 Northern California wildfires, partially offset by the $2.0 billion in required upfront shareholder contributions to the customer credit trust. As of December 31, 2025, the Utility had made all required upfront contributions. The Utility also recorded a $5.54 billion SB 901 securitization regulatory liability at inception, which represents certain shareholder tax benefits the Utility had previously recognized that will be returned to customers. As tax benefits are monetized, contributions will be made to the customer credit trust, up to $7.59 billion. The Utility expects to amortize the SB 901 securitization regulatory asset and liability over the life of the recovery bonds, with such amortization reflected in Operating and maintenance expense in the Consolidated Statements of Income. During the years ended December 31, 2025 and 2024, the Utility recorded $302 million and $328 million, respectively, for amortization of the regulatory asset and liability in the Consolidated Statements of Income.

The following tables illustrate the changes in the SB 901 securitization's impact on the Utility's regulatory assets and liabilities:

	SB 901 securitization regulatory asset	
(in millions)	**2025**	**2024**
Balance at January 1	**$ 5,194**	**$ 5,249**
Amortization	(105)	(55)
Balance at December 31	**$ 5,089**	**$ 5,194**

(in millions)	SB 901 securitization regulatory liability 2025	2024
Balance at January 1	**$ (6,295)**	**$ (6,628)**
Amortization	407	383
Additions[1]	(122)	(50)
Balance at December 31	**$ (6,010)**	**$ (6,295)**

[1] Includes $87 million and $16 million of returns on investments in the customer credit trust expected to be credited to customers for the years ended December 31, 2025 and 2024, respectively.

NOTE 6: COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 2,197,942,874 shares of common stock outstanding at December 31, 2025, excluding 477,743,590 shares of common stock owned by the Utility. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2025.

On December 4, 2024, PG&E Corporation issued 55,961,070 shares of common stock, no par value, for cash proceeds of approximately $1.13 billion. The proceeds from this issuance are intended to be used for general corporate purposes, which may include, among other things, to fund its five-year capital investment plan.

Dividends

CPUC holding company rules require that the Utility's dividend policy be established by the Utility's Board of Directors on the same basis as if the Utility were a stand-alone utility company, and that the capital requirements of Utility, as deemed to be necessary to meet the Utility's electricity service obligations, receive first priority from the Boards of Directors of both PG&E Corporation and the Utility. The CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average.

California law requires that a corporation must pass either a retained earnings test or an asset to liabilities ratio test to declare a dividend, ensuring it can meet its liabilities as they mature.

Additionally, neither PG&E Corporation nor the Utility may pay common stock dividends unless all cumulative preferred dividends on PG&E Corporation's Mandatory Convertible Preferred Stock and the Utility's preferred stock, respectively, have been paid.

Subject to the foregoing restrictions, any decision to declare and pay dividends in the future will be made at the discretion of PG&E Corporation's and the Utility's 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.

The following table summarizes the dividends on common stock paid or declared by PG&E Corporation and the Utility in 2025:

Security	Amount per Share	Aggregate amount (in millions)	Date of Declaration	Record Date	Payment Date
PG&E Corporation common stock	$ 0.025	$ 55	November 29, 2024	December 31, 2024	January 15, 2025
	0.025	55	February 20, 2025	March 31, 2025	April 15, 2025
	0.025	55	May 22, 2025	June 30, 2025	July 15, 2025
	0.025	55	September 18, 2025	September 30, 2025	October 15, 2025
	0.05	110	December 11, 2025	December 31, 2025	January 15, 2026
Utility common stock	[1]	575	February 20, 2025	[1]	March 18, 2025
	[1]	575	May 22, 2025	[1]	May 30, 2025
	[1]	575	September 18, 2025	[1]	September 26, 2025
	[1]	625	December 11, 2025	[1]	December 18, 2025

[1] PG&E Corporation owns all of the outstanding shares of Utility common stock.

Long-Term Incentive Plans

The LTIP (i.e., the PG&E Corporation 2014 LTIP or the PG&E Corporation 2021 LTIP, as applicable) 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 51,401,320 shares were available for future awards at December 31, 2025.

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

(in millions)	2025	2024	2023
Restricted stock units	80	67	64
Performance shares	54	31	27
Total compensation expense (pre-tax)	**$ 134**	**$ 98**	**$ 91**
Total compensation expense (after-tax)	**$ 97**	**$ 71**	**$ 65**

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 grant date. 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, 2025, there were no unrecognized compensation costs related to nonvested stock options for PG&E Corporation.

The fair value of each stock option on the grant date is estimated using the Black-Scholes valuation method. No stock options were granted in 2025 or 2024.

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the grant date. 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 grant date. 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, 2025.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2025:

	Number of Stock Options	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term (Years)
Outstanding at January 1	743,963	$ 10.23	
Granted [1]	—	—	
Exercised	—	—	
Forfeited or expired	(111,495)	10.23	
Outstanding at December 31	632,468	10.23	1.91
Vested or expected to vest at December 31	632,468	10.23	1.91
Exercisable at December 31	632,468	$ 10.23	1.91

[1] Represents additional payout of existing stock option grants.

Restricted Stock Units

Restricted stock units 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 2025, 2024, and 2023 was $16.43, $16.74, and $15.70, respectively. The total fair value of restricted stock units that vested during 2025, 2024, and 2023 was $70 million, $62 million, and $64 million, respectively. The tax benefit from restricted stock units that vested in 2025 was $8 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, 2025, $108 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.60 years.

The following table summarizes restricted stock unit activity for 2025:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	9,423,582	$ 15.52
Granted	6,252,871	16.43
Vested	(4,744,176)	14.66
Forfeited	(254,623)	16.21
Nonvested at December 31	**10,677,654**	$ 16.42

Performance Shares

Performance shares generally 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 awards based on internal metrics. The weighted average grant-date fair value for performance shares granted during 2025, 2024, and 2023 was $15.10, $16.94, and $13.39 respectively. In general, forfeitures are recorded ratably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2025, $39 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.14 years.

The following table summarizes activity for performance shares in 2025:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	7,180,206	$ 15.52
Granted	2,445,690	15.10
Vested	(2,831,269)	11.21
Forfeited	(332,132)	16.39
Nonvested at December 31	**6,462,495**	$ 16.40

NOTE 7: PREFERRED STOCK

PG&E Corporation

PG&E Corporation has authorized 400 million shares of preferred stock.

On December 5, 2024, PG&E Corporation issued 32,200,000 shares of 6.000% Series A Mandatory Convertible Preferred Stock, at $50.00 per share, for cash proceeds of approximately $1.6 billion. The proceeds from this issuance are intended to be used for general corporate purposes, which may include, among other things, to fund its five-year capital investment plan.

Each share of the Mandatory Convertible Preferred Stock will automatically convert on December 1, 2027. The number of shares of common stock issuable on conversion of Mandatory Convertible Preferred Stock will not be more than 2.4331 shares of common stock and not less than 1.9465 shares of common stock.

Other than during a Fundamental Change Conversion Period (as defined in the PG&E Corporation Preferred Stock Certificate of Designation), at any time prior to December 1, 2027, holders of Mandatory Convertible Preferred Stock have the option to elect to convert their shares of the Mandatory Convertible Preferred Stock, in whole or in part (but in no event in increments of less than one share of the Mandatory Convertible Preferred Stock), into shares of common stock at the Minimum Conversion Rate of 1.9465 shares of common stock per share of Mandatory Convertible Preferred Stock, subject to adjustment as described in the Preferred Stock Preliminary Prospectus Supplement.

Utility

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, 2025 and 2024, the Utility's preferred stock outstanding included $145 million of shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $113 million of shares with interest rates between 4.36% and 5% that are redeemable between $25.75 and $27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. No shares of $100 first preferred stock are outstanding.

Dividends

PG&E Corporation

All shares of the Mandatory Convertible Preferred Stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of the Mandatory Convertible 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.

Dividends on the Mandatory Convertible Preferred Stock are cumulative. The Mandatory Convertible Preferred Stock ranks senior to PG&E Corporation's common stock with respect to the payment of dividends. Accordingly, unless accumulated dividends have been paid on all of the Mandatory Convertible Preferred Stock through the most recently completed dividend period, no dividends may be declared or paid on PG&E Corporation's common stock and PG&E Corporation will not be permitted to repurchase any of its common stock, subject to limited exceptions.

Utility

At December 31, 2025, 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, 2025, annual dividends on the Utility's redeemable preferred stock ranged from $1.09 to $1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

The following table summarizes the dividends on preferred stock paid or declared by PG&E Corporation and the Utility in 2025:

Security	Amount per Share	Aggregate amount (in millions)	Date of Declaration	Record Date	Payment Date
PG&E Corporation mandatory convertible preferred stock	$ 0.7167	$ 23	December 12, 2024	February 14, 2025	February 27, 2025
	0.75	24	February 20, 2025	May 15, 2025	May 29, 2025
	0.75	24	May 22, 2025	August 15, 2025	August 28, 2025
	0.75	24	September 18, 2025	November 14, 2025	December 1, 2025
	0.75	24	December 11, 2025	February 13, 2026	March 1, 2026
Utility preferred stock	varies by series	3.5	November 29, 2024	January 31, 2025	February 15, 2025
	varies by series	3.5	February 20, 2025	April 30, 2025	May 15, 2025
	varies by series	3.5	May 22, 2025	July 31, 2025	August 15, 2025
	varies by series	3.5	September 18, 2025	October 31, 2025	November 15, 2025
	varies by series	3.5	December 11, 2025	January 30, 2026	February 15, 2026

For more information on dividend policy, see Note 6 above.

NOTE 8: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income 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 2025, 2024, and 2023.

	Year Ended December 31,		
(in millions, except per share amounts)	**2025**	**2024**	**2023**
Income available for common shareholders	$ 2,593	$ 2,475	$ 2,242
Weighted average common shares outstanding, basic (1)	2,197	2,141	2,064
Add incremental shares from assumed conversions:			
Employee share-based compensation	5	6	6
Equity Units	—	—	68
Weighted average common shares outstanding, diluted	2,202	2,147	2,138
Total earnings per common share, diluted	**$ 1.18**	**$ 1.15**	**$ 1.05**

(1) Excludes 477,743,590 shares of PG&E Corporation common stock held by the Utility.

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant number of options and securities that were antidilutive. For the year ended December 31, 2025, the calculation of outstanding common shares on a diluted basis excluded the impacts of the Mandatory Convertible Preferred Stock (see Note 7 above), which were antidilutive. In addition, as a result of an irrevocable election made on December 8, 2023 to fix the settlement method to Combination Settlement, the Convertible Notes (as defined in Note 4) did not have a material impact on the calculation of diluted EPS.

NOTE 9: INCOME TAXES

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

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.

In general, 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 expense (benefit) were as follows:

	PG&E Corporation			**Utility**		
	Year Ended December 31,					
(in millions)	**2025**	**2024**	**2023**	**2025**	**2024**	**2023**
Current:						
Federal	$ (1)	$ 2	$ (1)	$ (1)	$ 2	$ (1)
State	50	(78)	—	89	(78)	—
Deferred:						
Federal	(225)	(137)	(1,047)	(171)	(72)	(981)
State	(102)	15	(507)	(109)	45	(477)
Federal tax credits	(2)	(2)	(2)	(2)	(2)	(2)
Total income tax benefit	**$ (280)**	**$ (200)**	**$ (1,557)**	**$ (194)**	**$ (105)**	**$ (1,461)**

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

	PG&E Corporation		Utility	
	Year Ended December 31,			
(in millions)	**2025**	**2024**	**2025**	**2024**
Deferred income tax assets:				
Tax carryforwards	$ 9,752	$ 9,429	$ 9,199	$ 8,955
Compensation	211	171	127	86
GHG allowances	457	471	457	471
Wildfire-related claims (1)	227	295	227	295
Operating lease liability	111	78	111	78
Transmission tower wireless license	251	251	251	251
Bad debt	137	127	137	127
Other (2)	127	140	156	137
Total deferred income tax assets	**$ 11,273**	**$ 10,962**	**$ 10,665**	**$ 10,400**
Deferred income tax liabilities:				
Property-related basis difference	12,357	11,021	12,344	11,009
Regulatory balancing accounts	487	878	487	878
Income tax regulatory asset (3)	1,723	1,335	1,723	1,335
Debt financing costs	353	390	353	390
Operating lease ROU asset	111	78	111	78
Environmental reserve	288	248	288	248
Other (4)	89	94	91	94
Total deferred income tax liabilities	**$ 15,408**	**$ 14,044**	**$ 15,397**	**$ 14,032**
Total net deferred income tax liabilities	**$ 4,135**	**$ 3,082**	**$ 4,732**	**$ 3,632**

(1) Amounts primarily relate to wildfire-related claims, net of recoveries, and legal and other costs related to various wildfires that have occurred in the Utility's service area over the past several years.
(2) Amounts include benefits, state taxes, 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.
(4) Amounts primarily include property taxes.

The following tables reconcile income tax expense at the federal statutory rate to the income tax provision:

	PG&E Corporation					
	Year Ended December 31,					
(in millions)	**2025**		**2024**		**2023**	
Federal statutory income tax rate	21.0 %	$ 486	21.0 %	$ 478	21.0 %	$ 144
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	(1.8)	(41)	(2.0)	(45)	(57.9)	(397)
Effect of regulatory treatment of fixed asset differences (2)	(34.2)	(790)	(28.9)	(657)	(62.4)	(428)
Changes in valuation allowance	0.8	18	(0.9)	(20)	0.7	5
Nontaxable or nondeductible items	2.2	51	0.8	19	0.2	1
Tax credits	(1.1)	(26)	(1.0)	(22)	(3.4)	(24)
Changes in unrecognized tax benefits	0.1	3	2.1	46	0.2	2
Fire Victim Trust (3)	—	—	—	—	(126.9)	(869)
Other, net	0.9	19	0.1	1	1.3	9
Effective tax rate	**(12.1)%**	**$ (280)**	**(8.8)%**	**$ (200)**	**(227.2)%**	**$ (1,557)**

(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.
(3) Includes an adjustment for the tax benefit of the sale of shares by the Fire Victim Trust in 2023.

	Utility					
	Year Ended December 31,					
(in millions)	2025		2024		2023	
Federal statutory income tax rate	21.0 %	$ 606	21.0 %	$ 547	21.0 %	$ 228
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	(0.6)	(16)	(0.8)	(22)	(34.4)	(373)
Effect of regulatory treatment of fixed asset differences (2)	(27.4)	(790)	(25.2)	(657)	(39.5)	(428)
Changes in valuation allowance	—	—	—	—	0.1	1
Nontaxable or nondeductible items	1.1	30	0.4	12	—	—
Tax credits	(0.9)	(26)	(0.9)	(22)	(2.2)	(24)
Changes in unrecognized tax benefits	0.1	3	1.9	49	0.2	2
Fire Victim Trust (3)	—	—	—	—	(80.2)	(869)
Other, net	—	(1)	(0.4)	(12)	0.2	2
Effective tax rate	**(6.7)%**	**$ (194)**	**(4.0)%**	**$ (105)**	**(134.8)%**	**$ (1,461)**

(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.
(3) Includes an adjustment for the tax benefit of the sale of shares by the Fire Victim Trust in 2023.

Unrecognized Tax Benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
(in millions)	2025	2024	2023	2025	2024	2023
Balance at beginning of year	$ 454	$ 616	$ 570	$ 454	$ 616	$ 570
Additions for tax position taken during a prior year	5	—	1	5	—	1
Reductions for tax position taken during a prior year	(7)	(257)	—	(7)	(257)	—
Additions for tax position taken during the current year	665	95	45	665	95	45
Balance at end of year	**$ 1,117**	**$ 454**	**$ 616**	**$ 1,117**	**$ 454**	**$ 616**

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2025 for PG&E Corporation and the Utility was $102 million.

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months based on tax audit progress.

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, 2025, 2024, and 2023, these amounts were immaterial.

Tax Audits

PG&E Corporation's tax returns have been accepted through 2015 for federal income tax purposes. The IRS is auditing PG&E Corporation's tax returns for 2015 through 2018. The most significant unresolved matter relates to the deductibility of approximately $850 million in costs for San Bruno related safety spend, which the CPUC did not allow the Utility to recover through rates, and $400 million in customer bill credits. PG&E Corporation records an income tax benefit related to a deduction for an uncertain tax position when it determines it is more likely than not that the uncertain tax position will ultimately be sustained. On June 4, 2024, the Office of Chief Counsel of the IRS issued a technical advice memorandum taking the position that the costs the Utility incurred for San Bruno related to safety spend and customer bill credits are nondeductible fines or penalties. PG&E Corporation decreased its Income tax benefit by $70 million related to state and federal income taxes in 2024. PG&E Corporation intends to defend itself vigorously as to all costs in this matter.

Carryforwards

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

(in millions)		December 31, 2025	Expiration Year
Federal:			
Net operating loss carryforward - Pre-2018	$	3,307	2031 - 2036
Net operating loss carryforward - Post-2017		34,957	N/A
Tax credit carryforward		226	Various
State:			
Net operating loss carryforward	$	34,143	2039 - 2041
Tax credit carryforward		167	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.

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	
Underlying Product	**Instruments**	**December 31, 2025**	**December 31, 2024**
Natural Gas [1] (MMBtus [2])	Forwards, futures, and swaps	232,825,834	179,257,247
	Options	48,215,000	37,717,500
Electricity (MWh)	Forwards, futures, and swaps	7,196,942	8,576,078
	Options	1,650,800	1,663,200
	Congestion Revenue Rights [3]	93,712,644	123,040,895

[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

As of December 31, 2025, the Utility's outstanding derivative balances were as follows:

	Commodity Risk		
(in millions)	**Gross Derivative Balance**	**Netting**	**Total Derivative Balance**
Current assets – other	$ 165	$ (46)	$ 119
Noncurrent assets – other	170	(6)	164
Current liabilities – other	(169)	46	(123)
Noncurrent liabilities – other	(106)	6	(100)
Total commodity risk	**$ 60**	**$ —**	**$ 60**

As of December 31, 2024, the Utility's outstanding derivative balances were as follows:

	Commodity Risk		
(in millions)	**Gross Derivative Balance**	**Netting**	**Total Derivative Balance**
Current assets – other	$ 186	$ (16)	$ 170
Noncurrent assets – other	233	—	233
Current liabilities – other	(152)	16	(136)
Noncurrent liabilities – other	(167)	—	(167)
Total commodity risk	**$ 100**	**$ —**	**$ 100**

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 derivative 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, 2025, 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, self-insurance assets, 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, 2025				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Assets:					
Short-term investments	$ 634	$ —	$ —	$ —	**$ 634**
Fixed-income securities	—	—	—	—	**—**
Self-insurance investments					
Short-term investments	1,120	—	—	—	**1,120**
Total Self-insurance investments [2]	**1,120**	**—**	**—**	**—**	**1,120**
Nuclear decommissioning trusts					
Short-term investments	94	—	—	—	**94**
Global equity securities	2,433	—	—	—	**2,433**
Fixed-income securities	1,445	1,113	—	—	**2,558**
Assets measured at NAV	—	—	—	—	**26**
Total nuclear decommissioning trusts [3]	**3,972**	**1,113**	**—**	**—**	**5,111**
Customer credit trust					
Short-term investments	111	—	—	—	**111**
Global equity securities	—	—	—	—	**—**
Fixed-income securities	367	326	—	—	**693**
Total customer credit trust	**478**	**326**	**—**	**—**	**804**
Price risk management instruments (Note 10)					
Electricity	—	19	283	(6)	**296**
Gas	—	33	—	(46)	**(13)**
Total price risk management instruments	**—**	**52**	**283**	**(52)**	**283**
Rabbi trusts					
Short-term investments	115	—	—	—	**115**
Global equity securities	5	—	—	—	**5**
Life insurance contracts	—	65	—	—	**65**
Total rabbi trusts	**120**	**65**	**—**	**—**	**185**
Long-term disability trust					
Short-term investments	10	—	—	—	**10**
Assets measured at NAV	—	—	—	—	**127**
Total long-term disability trust	**10**	**—**	**—**	**—**	**137**
TOTAL ASSETS	**$ 6,334**	**$ 1,556**	**$ 283**	**$ (52)**	**$ 8,274**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ —	$ 80	$ 130	$ (6)	**$ 204**
Gas	—	65	—	(46)	**19**
TOTAL LIABILITIES	**$ —**	**$ 145**	**$ 130**	**$ (52)**	**$ 223**

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements.
[2] Includes $1 billion and $77 million held in the entities for wildfire and non-wildfire self-insurance, respectively.

(3) Represents amount before deducting $881 million primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements At December 31, 2024				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting (1)**	**Total**
Assets:					
Short-term investments	$ 826	$ —	$ —	$ —	**$ 826**
Pacific Energy Risk Solutions, LLC					
Short-term investments	905	—	—	—	**905**
Total Pacific Energy Risk Solutions, LLC	**905**	—	—	—	905
Nuclear decommissioning trusts					
Short-term investments	53	—	—	—	**53**
Global equity securities	2,228	—	—	—	**2,228**
Fixed-income securities	1,250	1,027	—	—	**2,277**
Assets measured at NAV	—	—	—	—	**22**
Total nuclear decommissioning trusts (2)	**3,531**	**1,027**	**—**	**—**	**4,580**
Customer credit trust					
Short-term investments	1	—	—	—	**1**
Global equity securities	186	—	—	—	**186**
Fixed-income securities	46	144	—	—	**190**
Total customer credit trust	**233**	**144**	**—**	**—**	**377**
Price risk management instruments (Note 10)					
Electricity	—	26	383	(6)	**403**
Gas	—	10	—	(10)	**—**
Total price risk management instruments	**—**	**36**	**383**	**(16)**	**403**
Rabbi trusts					
Short-term investments	107	—	—	—	**107**
Global equity securities	6	—	—	—	**6**
Life insurance contracts	—	66	—	—	**66**
Total rabbi trusts	**113**	**66**	**—**	**—**	**179**
Long-term disability trust					
Short-term investments	4	—	—	—	**4**
Assets measured at NAV	—	—	—	—	**130**
Total long-term disability trust	**4**	**—**	**—**	**—**	**134**
TOTAL ASSETS	**$ 5,612**	**$ 1,273**	**$ 383**	**$ (16)**	**$ 7,404**
Liabilities:					
Price risk management instruments (Note 10)					
Electricity	$ —	$ 37	$ 248	$ (6)	**$ 279**
Gas	—	34	—	(10)	**24**
TOTAL LIABILITIES	**$ —**	**$ 71**	**$ 248**	**$ (16)**	**$ 303**

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements.
(2) Represents amount before deducting $747 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, 2025 or 2024.

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, customer credit 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 classified as 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.

Self-insurance investments

Investments held in Pacific Energy Risk Solutions, LLC and Pacific Casualty Insurance Company, LLC primarily include short-term investments that are U.S. government securities classified as Level 1.

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 on net income resulting from changes in the fair value of these instruments. See Note 10 above.

	Fair Value (in millions) At December 31, 2025					
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range [(1)]/Weighted-Average Price [(2)]
Congestion revenue rights	$ 252	$ 83	Market approach	CRR auction prices	$ (74) - 74 / 2
Power purchase agreements	$ 31	$ 47	Discounted cash flow	Forward prices	$ 11 - 106 / 53

(1) Represents price per MWh.
(2) Unobservable inputs were weighted by the relative fair value of the instruments.

	Fair Value (in millions) At December 31, 2024				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range [(1)]/Weighted-Average Price [(2)]
Congestion revenue rights	$ 366	$ 121	Market approach	CRR auction prices	$ (951) - 50,044 / 2
Power purchase agreements	$ 17	$ 127	Discounted cash flow	Forward prices	$ 0 - 126 / 47

(1) Represents price per MWh.
(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, 2025 and 2024:

	Price Risk Management Instruments	
(in millions)	**2025**	**2024**
Asset balance as of January 1	**$ 127**	**$ 191**
Net realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [(1)]	26	(64)
Asset balance as of December 31	**$ 153**	**$ 127**

(1) The costs related to price risk management activities are recovered through 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, and customer deposits approximate their carrying values as of December 31, 2025 and December 31, 2024, 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, 2025		At December 31, 2024	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
Debt (Note 4)				
PG&E Corporation [(1)]	$ 5,360	$ 5,697	$ 5,358	$ 5,829
Utility	38,145	35,565	37,812	34,532

(1) As of December 31, 2025, the net carrying amount and the estimated fair value (Level 2) of the Convertible Notes were $2.1 billion and $2.2 billion, respectively.

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, 2025				
Nuclear decommissioning trusts				
Short-term investments	$ 94	$ —	$ —	$ 94
Global equity securities	324	2,140	(5)	2,459
Fixed-income securities	2,557	48	(47)	2,558
Total [(1)]	**$ 2,975**	**$ 2,188**	**$ (52)**	**$ 5,111**
As of December 31, 2024				
Nuclear decommissioning trusts				
Short-term investments	$ 54	$ —	$ (1)	$ 53
Global equity securities	353	1,907	(10)	2,250
Fixed-income securities	2,341	20	(84)	2,277
Total [(1)]	**$ 2,748**	**$ 1,927**	**$ (95)**	**$ 4,580**

(1) Represents amounts before deducting $881 million and $747 million as of December 31, 2025 and December 31, 2024, 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, 2025
Less than 1 year	$ 95
1–5 years	822
5–10 years	564
More than 10 years	1,077
Total maturities of fixed-income securities	**$ 2,558**

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

(in millions)	2025	2024	2023
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 1,952	$ 1,980	$ 2,235
Gross realized gains on securities	213	255	80
Gross realized losses on securities	(25)	(63)	(74)

Customer Credit Trust

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, 2025				
Customer credit trust				
Short-term investments	$ 111	$ —	$ —	$ 111
Global equity securities	—	—	—	—
Fixed-income securities	689	5	(1)	693
Total	**$ 800**	**$ 5**	**$ (1)**	**$ 804**
As of December 31, 2024				
Customer credit trust				
Short-term investments	$ 1	$ —	$ —	$ 1
Global equity securities	161	28	(3)	186
Fixed-income securities	193	1	(4)	190
Total	**$ 355**	**$ 29**	**$ (7)**	**$ 377**

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

(in millions)	As of December 31, 2025
Less than 1 year	$ 290
1–5 years	107
5–10 years	49
More than 10 years	247
Total maturities of fixed-income securities	**$ 693**

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

(in millions)	2025	2024	2023
Proceeds from sales and maturities of customer credit trust investments	$ 435	$ 398	$ 556
Gross realized gains on securities	131	10	$ 23
Gross realized losses on securities	(20)	(8)	$ (19)

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 2025 and 2024:

Pension Plan

(in millions)	2025	2024
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 16,767**	**$ 17,211**
Actual return on plan assets	1,779	218
Company contributions	337	337
Benefits and expenses paid	(1,020)	(999)
Fair value of plan assets at end of year	**$ 17,863**	**$ 16,767**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 17,585**	**$ 17,697**
Service cost for benefits earned	424	396
Interest cost	1,007	916
Actuarial loss (gain) [1]	427	(424)
Benefits and expenses paid	(1,020)	(1,000)
Benefit obligation at end of year [2]	**$ 18,423**	**$ 17,585**
Funded Status:		
Current liability	$ (10)	$ (10)
Noncurrent liability	(550)	(808)
Net liability at end of year	**$ (560)**	**$ (818)**

[1] The actuarial loss for the year ended December 31, 2025 was due to a decrease in the discount rate used to measure the projected benefit obligation and unfavorable changes in demographic assumptions; the actuarial gain for the year ended December 31, 2024 was due to an increase in the discount rate used to measure the projected benefit obligation, offset by an unfavorable return on plan assets and unfavorable changes in the demographic assumptions.

[2] PG&E Corporation's accumulated benefit obligation was $16.5 billion and $15.8 billion at December 31, 2025 and 2024, respectively.

Postretirement Benefits Other than Pensions

(in millions)	2025	2024
Change in plan assets:		
Fair value of plan assets at beginning of year	**$ 2,471**	**$ 2,499**
Actual return on plan assets	200	74
Company contributions	7	5
Plan participant contribution	91	84
Benefits and expenses paid	(196)	(191)
Fair value of plan assets at end of year	**$ 2,573**	**$ 2,471**
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 1,279**	**$ 1,377**
Service cost for benefits earned	38	41
Interest cost	73	71
Actuarial loss (gain) [(1)]	125	(123)
Benefits and expenses paid	(182)	(174)
Federal subsidy on benefits paid	4	3
Plan participant contributions	91	84
Benefit obligation at end of year	**$ 1,428**	**$ 1,279**
Funded Status: [(2)]		
Noncurrent asset	$ 1,144	$ 1,192
Noncurrent liability	—	—
Net asset at end of year	**$ 1,144**	**$ 1,192**

(1) The actuarial loss for the year ended December 31, 2025 was primarily due to a decrease in the discount rate used to measure the accumulated benefit obligations and unfavorable changes in claims cost, medical trends, and demographic assumptions. The actuarial gain for the year ended December 31, 2024 was primarily due to an increase in the discount rate used to measure the accumulated benefit obligations and favorable changes in demographic assumptions, offset by an unfavorable return on plan assets.

(2) At December 31, 2025 and 2024, the postretirement medical plan and the postretirement life insurance plan were in overfunded positions. The projected benefit obligation and the fair value of plan assets for the postretirement life insurance plan were $274 million and $322 million as of December 31, 2025, and $261 million and $296 million as of December 31, 2024, 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 Plan” below. Post-retirement medical and life insurance plans are included in “Postretirement Benefits Other than Pensions” below.

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

Pension Plan

(in millions)	2025	2024	2023
Service cost for benefits earned [1]	$ 424	$ 396	$ 379
Interest cost	1,007	916	913
Expected return on plan assets	(1,053)	(1,014)	(981)
Amortization of prior service cost	(3)	(3)	(4)
Amortization of net actuarial loss	2	1	1
Net periodic benefit cost	**377**	**296**	**308**
Less: transfer to regulatory account [2]	(40)	39	25
Total expense recognized	**$ 337**	**$ 335**	**$ 333**

[1] A portion of service costs are capitalized pursuant to ASC 715, *Compensation - Retirement Benefits.*
[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)	2025	2024	2023
Service cost for benefits earned [1]	$ 38	$ 41	$ 38
Interest cost	73	71	73
Expected return on plan assets	(150)	(139)	(132)
Amortization of prior service cost	3	3	3
Amortization of net actuarial gain	(23)	(23)	(19)
Net periodic benefit cost	**$ (59)**	**$ (47)**	**$ (37)**

[1] A portion of service costs are capitalized pursuant to ASC 715, *Compensation - Retirement Benefits.*

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,		
	2025	2024	2023	2025	2024	2023
Discount rate	5.58 %	5.76 %	5.21 %	5.51 - 5.60%	5.71 - 5.76%	5.18 - 5.22%
Rate of future compensation increases	4.80 %	4.80 %	3.80 %	N/A	N/A	N/A
Expected return on plan assets	7.00 %	6.40 %	6.00 %	4.30 - 7.20%	3.90 - 7.20%	3.70 - 7.00%
Interest crediting rate for cash balance plan	4.23 %	4.41 %	3.86 %	N/A	N/A	N/A

The assumed health care cost trend rate as of December 31, 2025 was 7.00%, gradually decreasing to the ultimate trend rate of approximately 4.5% in 2036 and beyond.

Expected rates of return on plan assets were developed by estimating future asset class 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 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 7.0% compares to a ten-year actual return of 5.7%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 831 Aa-grade non-callable bonds at December 31, 2025. 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 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 allocation between fixed income and equity 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		
	2026	2025	2024	2026	2025	2024
Global equity securities	28 %	26 %	26 %	14 %	30 %	29 %
Absolute return	1	1	1	—	—	—
Real assets	6	8	8	3	3	3
Fixed-income securities	65	65	65	83	67	68
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, 2025 and 2024.

	Fair Value Measurements							
	At December 31,							
	2025				2024			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Plan:								
Short-term investments	$ 452	$ 30	$ —	$ 482	$ 126	$ 47	$ —	$ 173
Global equity securities	1,445	—	—	1,445	1,310	—	—	1,310
Real assets	2	—	—	2	437	—	—	437
Fixed-income securities	1,990	6,880	12	8,882	2,180	6,367	16	8,563
Assets measured at NAV	—	—	—	7,052	—	—	—	6,284
Total	**$ 3,889**	**$ 6,910**	**$ 12**	**$ 17,863**	**$ 4,053**	**$ 6,414**	**$ 16**	**$ 16,767**
PBOP Plans:								
Short-term investments	$ 546	$ —	$ —	$ 546	$ 27	$ —	$ —	$ 27
Global equity securities	2	—	—	2	60	—	—	60
Real assets	—	—	—	—	20	—	—	20
Fixed-income securities	518	561	—	1,079	431	751	1	1,183
Assets measured at NAV	—	—	—	946	—	—	—	1,181
Total	**$ 1,066**	**$ 561**	**$ —**	**$ 2,573**	**$ 538**	**$ 751**	**$ 1**	**$ 2,471**
Total plan assets at fair value				**$ 20,436**				**$ 19,238**

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 private real estate funds. These funds are measured at NAV as a practical expedient.

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, 2025 or 2024.

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, 2025 and 2024:

(in millions) **For the year ended December 31, 2025**	**Fixed-Income**
Balance at beginning of year	$ 16
Actual return on plan assets:	
Relating to assets still held at the reporting date	7
Relating to assets sold during the period	(7)
Purchases, issuances, sales, and settlements:	
Purchases	6
Settlements	(10)
Balance at end of year	**$ 12**

(in millions) **For the year ended December 31, 2024**	**Fixed-Income**
Balance at beginning of year	$ 13
Actual return on plan assets:	
Relating to assets still held at the reporting date	9
Relating to assets sold during the period	(9)
Purchases, issuances, sales, and settlements:	
Purchases	14
Settlements	(11)
Balance at end of year	**$ 16**

There were no material transfers out of Level 3 in 2025 or 2024.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed $337 million to the pension benefit plans, $31 million to the long-term disability trusts, and $7 million to the other postretirement benefit plans in 2025. 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. The Utility's pension benefits met all funding requirements under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation and the Utility expect to make total contributions of approximately $327 million to the qualified pension plan in 2026. PG&E Corporation and the Utility plan to contribute $31 million to the long-term disability trusts in 2026, as authorized in the 2023 GRC.

Benefits Payments and Receipts

As of December 31, 2025, 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**
2026	993	84	(1)
2027	1,082	86	(1)
2028	1,110	90	(1)
2029	1,136	93	(1)
2030	1,161	96	(1)
2031-2035	6,159	523	(6)

There were no material differences between the estimated benefits expected to be paid by PG&E Corporation and 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 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 IRC. This plan permits eligible employees to make pre-tax and after-tax contributions into the plan and provides 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 $194 million, $175 million, and $158 million in 2025, 2024, and 2023, respectively. PG&E Corporation's default matching contributions under its 401(k) plan are in cash.

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) plus five percent of direct labor costs or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are priced at the lower of fully loaded cost or fair market value. 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.

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. PG&E Corporation and the Utility record a provision for a loss contingency when they determine that 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 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.

Assessing whether a loss is probable or reasonably possible, whether the loss or a range of losses is estimable, and the amount of the accrual often requires management to exercise significant judgment about future events. Management makes these assessments based on a number of assumptions and subjective factors, including 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, and estimates based on currently available information and prior experience with wildfires. Unless expressly noted otherwise, the estimated liabilities in this Note reflect the lower end of the range of the reasonably estimable range of losses. PG&E Corporation and the Utility 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 or the upper end of the range because, as described below, 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.

Loss contingencies are reviewed quarterly, and estimates are adjusted to reflect the impact of all known information. 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. For instance, PG&E Corporation and the Utility receive additional information with respect to damages claimed as the claims mediation and trial processes progress. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated outside counsel 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.

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.

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 power lines and equipment 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. Although PG&E Corporation and the Utility may receive further complaints, the applicable statutes of limitations have expired, except for the statutes of limitations applicable to federal fire suppression claims for the 2021 Dixie fire and the 2022 Mosquito fire, which expire in 2027 and 2028, respectively. 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.

The Utility has made claims to the Wildfire Fund for claims paid in excess of $1.0 billion. Claims related to the 2019 Kincade fire are 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, USFS, 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.

The following table presents the cumulative amounts PG&E Corporation and the Utility have paid through December 31, 2025.

Payments (in millions)		
2019 Kincade Fire	$	1,287
2021 Dixie Fire		1,908
2022 Mosquito Fire		107
Total at December 31, 2025	**$**	**3,302**

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 area 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.

As of February 4, 2026, PG&E Corporation and the Utility are aware of approximately 135 complaints on behalf of at least 3,014 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. On July 20, 2022, PG&E Corporation and the Utility filed a motion for summary adjudication on individual plaintiffs' claims for punitive damages. On July 14, 2024, the court vacated the bellwether trial date that had been scheduled for August 26, 2024, as well as the hearing on the motion for summary adjudication.

On October 11, 2022, the Utility entered into a tolling agreement with Cal OES, extending their time to file a complaint.

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 $1.225 billion as of December 31, 2024 (before available insurance). In each of the first and second quarters of 2025, PG&E Corporation and the Utility recorded additional charges of $50 million, for an aggregate liability of $1.325 billion (before available insurance).

PG&E Corporation's and the Utility's accrued estimated losses represent the best estimate of the liability and do not include any claims related to Cal OES or any punitive damages.

The following table presents changes in the best estimate of PG&E Corporation's and the Utility's reasonably estimable losses, net of payments, for claims arising from the 2019 Kincade fire since December 31, 2024.

Loss Accrual (in millions)		
Balance at December 31, 2024	**$**	**267**
Accrued Losses		100
Payments		(329)
Balance at December 31, 2025	**$**	**38**

The Utility has fully collected its liability insurance coverage for third-party liability attributable to the 2019 Kincade fire, which was for an aggregate amount of $430 million.

As of December 31, 2025, the Utility received $111 million from the Wildfire Fund related to the 2019 Kincade fire. The Utility has recorded a deferred gain for this amount, which is included in Other noncurrent liabilities in PG&E Corporation's and the Utility's Consolidated Balance Sheets. See "Wildfire Fund Recoveries under AB 1054 and SB 254" below.

2021 Dixie Fire

According to the Cal Fire Investigation Report on the 2021 Dixie fire (the "Cal Fire Investigation Report"), on July 13, 2021, at approximately 5:07 p.m. Pacific Time, a wildfire began in the Feather River Canyon near Cresta Dam (the "2021 Dixie fire"), located in the service area of the Utility. According to the Cal Fire Investigation Report, the 2021 Dixie fire consumed 963,309 acres and resulted in 1,311 structures destroyed and 94 structures damaged (including 763 residential homes, 12 multi-family homes, 8 commercial residential homes, 148 nonresidential commercial structures, and 466 detached structures), and four first-responder injuries. The Cal Fire Investigation Report does not attribute a fatality that was previously published in an October 25, 2021 Cal Fire incident report to 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. On June 7, 2022, the Utility received a copy of the Cal Fire Investigation Report, which states that the fire ignited when a tree fell and contacted electrical distribution lines owned and operated by the Utility, and the Cal Fire Investigation Report has been made publicly available. The Cal Fire Investigation Report alleges that the Utility acted negligently in its response to the initial outage and fault that caused the 2021 Dixie fire. The Cal Fire Investigation Report also alleges that the subject tree had visible outward signs of damage and decay which would have been noticeable at the ground level, and that a brief visual inspection should have discovered the decay. Based on the information currently available to the Utility, through its ongoing investigation, including its inspection records, operating and inspection protocols and procedures, implementation of those protocols and procedures, and day-of-event response, the Utility believes its personnel acted reasonably (within the meaning of the applicable prudency standard discussed under "Regulatory Recovery" below) given the information available at the time and followed applicable policies and protocols both before ignition and in the day-of-event response. While an intervenor in a future cost recovery proceeding may argue the Cal Fire Investigation Report itself creates serious doubt with respect to the reasonableness of the Utility's conduct, PG&E Corporation and the Utility do not believe the report identifies sufficient facts to shift the burden of proof applicable in a proceeding for cost recovery to the Utility. (See "Regulatory Recovery" and "Wildfire Fund Recoveries under AB 1054 and SB 254" below.) PG&E Corporation and the Utility disagree with many allegations in the Cal Fire Investigation Report and plan to vigorously contest them. However, if the CPUC or the FERC were to reach conclusions similar to those of the Cal Fire Investigation Report, it may determine that the Utility had been imprudent, in which case some or all of its costs recorded to the WEMA would not be recoverable, the Utility would not be able to recover costs through FERC TO rates, or the Utility would be required to reimburse the Wildfire Fund for the costs and expenses that are allocated to it.

As of February 4, 2026, PG&E Corporation and the Utility are aware of approximately 189 complaints on behalf of at least 9,034 individual plaintiffs related to the 2021 Dixie fire. The plaintiffs seek damages that include wrongful death, property damage, economic loss, medical monitoring, punitive damages, exemplary damages, attorneys' fees and other damages. A trial with respect to one plaintiff has been scheduled for December 2, 2026. The court has scheduled and vacated numerous bellwether trial dates, including the previously scheduled bellwether trial date of June 23, 2025. No bellwether trial is scheduled. Pursuant to an agreed-upon alternative dispute resolution protocol, a voluntary process for plaintiffs to mediate their cases, when a mediation does not resolve a plaintiff's case, the plaintiff can opt to pursue a "damages-only" trial. One request for the court to set a damages-only trial is pending; the court has vacated all other previously scheduled damages-only trial dates.

Cal Fire filed a complaint against the Utility to recover suppression and investigation costs on June 30, 2023. The Utility filed an amended answer to the complaint on September 30, 2024. On October 10, 2024, Cal Fire filed a demurrer and motion to strike portions of the amended answer. On February 7, 2025, the court issued a ruling sustaining Cal Fire's demurrer and striking portions of the Utility's amended answer. On April 7, 2025, the Utility filed a petition for writ of mandate in the California First District Court of Appeal, seeking an order directing the trial court to reverse the ruling on Cal Fire's demurrer and motion to strike. On April 30, 2025, in response to the Court of Appeal's request, Cal Fire filed an opposition to the Utility's writ. The Utility filed a reply to the opposition on May 9, 2025. As of February 4, 2026, the writ remains pending with the Court of Appeal.

On February 7, 2023, the Utility entered into a tolling agreement with Cal OES, extending the agency's time to file a complaint. That tolling agreement remains in effect.

PG&E Corporation and the Utility are aware of a separate putative class complaint, primarily seeking relief in the form of medical monitoring. On January 28, 2026, plaintiffs filed their fifth amended complaint in that case. On December 12, 2025, plaintiffs filed their motion for class certification, and the hearing date on the motion is scheduled for June 18, 2026.

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 $1.925 billion as of December 31, 2024 (before available recoveries). Based on the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including their experience with settlements, PG&E Corporation and the Utility recorded additional charges during 2025 of $225 million, of which $25 million was recorded in the fourth quarter, for an aggregate liability of $2.150 billion (before available recoveries).

PG&E Corporation's and the Utility's accrued estimated losses of $2.150 billion do not include, among other things: (i) any amounts for potential penalties or fines 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 Cal Fire, including for fire suppression costs and damages related to federal land, (iv) class action medical monitoring 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, other than Cal Fire, 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. PG&E Corporation and the Utility are 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 parks and national forests that were affected by the 2021 Dixie fire. According to the Cal Fire Investigation Report, over $650 million of costs had been incurred in suppressing the 2021 Dixie fire. The Utility estimates that the fire burned approximately 70,000 acres of national parks and approximately 685,000 acres of national forests.

The following table presents changes in PG&E Corporation's and the Utility's reasonably estimable losses, net of payments, for claims arising from the 2021 Dixie fire since December 31, 2024.

Loss Accrual (in millions)		
Balance at December 31, 2024	**$**	**567**
Accrued Losses		225
Payments		(549)
Balance at December 31, 2025	**$**	**243**

As of December 31, 2025, the Utility recorded an insurance receivable of $521 million for probable insurance recoveries in connection with the 2021 Dixie fire.

The Utility recorded an aggregate Wildfire Fund receivable of $1.150 billion for probable recoveries in connection with the 2021 Dixie fire, of which it had received $851 million as of December 31, 2025. AB 1054 provides that the CPUC may allocate costs and expenses in the application for cost recovery in full or in part taking into account factors both within and beyond the utility's control that may have exacerbated the costs and expenses, including humidity, temperature, and winds. PG&E Corporation and the Utility believe that, even if it found that the Utility acted unreasonably, the CPUC would nevertheless authorize recovery in part. See "Wildfire Fund Recoveries under AB 1054 and SB 254" below. As of December 31, 2025, the Utility also recorded a $97 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 $535 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.

2022 Mosquito Fire

On September 6, 2022, at approximately 6:17 p.m. Pacific Time, the Utility was notified that a wildfire had ignited near Oxbow Reservoir in Placer County, California (the "2022 Mosquito fire"), located in the service area of the Utility. The National Wildfire Coordinating Group's InciWeb incident overview dated November 4, 2022 at 6:30 p.m. Pacific Time indicated that the 2022 Mosquito fire had consumed approximately 76,788 acres at that time. It also indicated no fatalities, no injuries, 78 structures destroyed, and 13 structures damaged (including 44 residential homes and 40 detached structures) and that the fire was 100% contained.

The USFS has indicated to the Utility an initial assessment that the fire started in the area of the Utility's power line on National Forest System lands and that the USFS is conducting a criminal investigation into the 2022 Mosquito fire. On September 24, 2022, the USFS removed and took possession of one of the Utility's transmission poles and attached equipment. The USFS has not issued a determination as to the cause.

The cause of the 2022 Mosquito fire remains under investigation by the USFS, the United States Department of Justice, and the CPUC. 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 2022 Mosquito fire. This investigation is ongoing.

As of February 4, 2026, PG&E Corporation and the Utility are aware of approximately 35 complaints on behalf of at least 2,939 individual plaintiffs related to the 2022 Mosquito fire. Placer County Water Agency ("PCWA"), Middle Fork Project Finance Authority, and a group of six public entities have each filed complaints. The plaintiffs seek damages that include property damage, economic loss, punitive damages, exemplary damages, attorneys' fees, and other damages. In January 2026, PG&E Corporation and the Utility entered into settlement agreements with five public entities. The court has set individual claimant bellwether trial dates for April 13, 2026.

On May 28, 2025, the Utility executed an amendment to a tolling agreement with Cal OES, extending the agency's time to file a complaint. That tolling agreement remains in effect.

On August 21, 2025, Cal Fire filed a complaint against the Utility for fire suppression and investigation costs.

Based on the current state of the law concerning inverse condemnation in California and the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, including the information gathered as part of PG&E Corporation's and the Utility's investigation, PG&E Corporation and the Utility believe it is probable that they will incur a loss in connection with the 2022 Mosquito fire. PG&E Corporation and the Utility recorded a liability in the aggregate amount of $100 million as of December 31, 2024 (before available recoveries). During 2025, PG&E Corporation and the Utility recorded additional charges of $250 million, of which $100 million was recorded in the fourth quarter, for an aggregate liability of $350 million (before available recoveries).

PG&E Corporation's and the Utility's accrued estimated losses do not include, among other things: (i) any amounts for potential penalties or fines that may be imposed by courts or other governmental entities on PG&E Corporation or the Utility, (ii) any punitive damages, (iii) amounts in respect of compensation claims by federal agencies for federal fire suppression costs and damages related to federal land, other than claims by PCWA or (iv) any other amounts that are not reasonably estimable.

As noted above, the aggregate estimated liability for claims in connection with the 2022 Mosquito fire does not include potential claims for fire suppression costs from federal 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. PG&E Corporation and the Utility are 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 2022 Mosquito fire.

The following table presents changes in PG&E Corporation’s and the Utility’s reasonably estimable losses, net of payments, for claims arising from the 2022 Mosquito fire since December 31, 2024.

Loss Accrual (in millions)		
Balance at December 31, 2024	**$**	**82**
Accrued Losses		250
Payments		(89)
Balance at December 31, 2025	**$**	**243**

As of December 31, 2025, the Utility recorded an insurance receivable of $363 million for probable insurance recoveries in connection with the 2022 Mosquito fire, including claims and legal fees. As of December 31, 2025, the Utility also recorded a $7 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 $54 million regulatory asset for costs that were determined to be probable of recovery through the WEMA. See “Regulatory Recovery” below.

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. 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 recoveries. For more information on the applicable facts and circumstances of the corresponding wildfires, see “2019 Kincade Fire,” “2021 Dixie Fire,” and “2022 Mosquito Fire.”

Total probable recoveries for the 2021 Dixie fire and the 2022 Mosquito fire as of December 31, 2025 are:

Potential Recovery Source (in millions)		**2021 Dixie fire**		**2022 Mosquito fire**
Insurance	$	521	$	363
FERC TO rates		97		7
WEMA		535		54
Wildfire Fund		1,150		—
Probable recoveries at December 31, 2025 [(1)]	**$**	**2,303**	**$**	**424**

(1) Includes legal costs of $148 million and $73 million related to the 2021 Dixie fire and 2022 Mosquito fire, respectively, as of December 31, 2025.

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 in this section, 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

Self-Insurance

Since August 2023, the Utility’s wildfire liability insurance for amounts up to $1.0 billion has been entirely based on self-insurance and will remain as such through at least 2026. The self-insurance program includes a 5% deductible, capped at a maximum of $50 million, on claims that are incurred each year.

Insurance Receivable

As of December 31, 2025, PG&E Corporation and the Utility have recorded total probable insurance recoveries of $521 million and $363 million in connection with the 2021 Dixie fire and the 2022 Mosquito fire, respectively. 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. The following table presents changes in accrued insurance recoveries, net of reimbursements received, for the 2021 Dixie fire and 2022 Mosquito fire since December 31, 2024:

Insurance Receivable (in millions)	**2021 Dixie fire**	**2022 Mosquito fire**	**Total**
Balance at December 31, 2024	**$ 27**	**$ 90**	**$ 117**
Accrued insurance recoveries	(6)	273	267
Reimbursements	(20)	(82)	(102)
Balance at December 31, 2025	**$ 1**	**$ 281**	**$ 282**

Regulatory Recovery

Section 451.1 of the Public Utilities Code provides that when determining an application to recover costs and expenses arising from a covered wildfire, the CPUC shall allow cost recovery if the costs and expenses are just and reasonable (i.e., the "prudency standard"). AB 1054 states that a utility with a valid safety certification for the time period in which a covered wildfire ignited "shall be deemed to have been reasonable" unless "a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct," in which case the burden shifts to the utility to prove its conduct was reasonable. The Utility had a valid safety certification at the time of the 2021 Dixie fire and the 2022 Mosquito fire, so any analysis of cost recovery starts with this reasonableness presumption. AB 1054 also allows the CPUC to allocate costs and expenses "in full or in part taking into account factors both within and beyond the Utility's control that may have exacerbated the costs and expenses, including humidity, temperature, and winds."

The Utility's recorded receivables under the WEMA and with respect to the Wildfire Fund take into account this revised prudency standard and the presumption of reasonableness of the Utility's conduct, based on the Utility's interpretation of AB 1054 and the information currently available to the Utility. Although the concept of "serious doubt" has been applied in other regulatory proceedings, such as FERC proceedings, the revised prudency standard under AB 1054 has not been interpreted or applied by the CPUC and it is possible that the CPUC could interpret or apply the standard differently, in which case the Utility may not be able to recover all or a portion of expenses that it has recorded as a receivable.

FERC TO Rates

The Utility recognizes income and reduces its regulatory liability for potential refund through future FERC TO formula rates for a portion of the third-party wildfire-related claims in excess of insurance coverage. The FERC presumes that a utility's expenditures are prudent and permits cost recovery unless a party raises a serious doubt regarding the prudency of such costs. 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 and the 2022 Mosquito fire, as of December 31, 2025, the Utility recorded reductions of $97 million and $7 million, respectively, to its regulatory liability for wildfire-related claims costs that were determined to be probable of recovery through the FERC TO formula rate.

WEMA

The WEMA provides for tracking of incremental wildfire claims, outside legal costs, and insurance premiums above those authorized in rates. With respect to wildfire claims and outside legal costs, the Utility expects that the same prudency standard as applies to the Wildfire Fund would also be applied in any CPUC review of an application filed by the Utility seeking recovery of such costs recorded to the WEMA. See "Wildfire Fund Recoveries under AB 1054 and SB 254" below. As of December 31, 2025, based on information currently available to the Utility, incremental wildfire claims-related costs for the 2021 Dixie fire and the 2022 Mosquito fire were determined to be probable of recovery, and the Utility recorded $535 million and $54 million, respectively, as regulatory assets in the WEMA.

Wildfire Fund Recoveries under AB 1054 and SB 254

AB 1054 became law on July 12, 2019, and SB 254 became law on September 19, 2025. AB 1054 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. SB 254 provides for a Continuation Account which is designed to provide additional liquidity to reimburse catastrophic wildfire-related claims that occur after September 19, 2025, subject to the terms and conditions of SB 254. Each of California's large electric IOUs has elected to participate in the Wildfire Fund and the Continuation Account. 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 arising from wildfires 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, 2025 reflects an expectation that the coverage year will be based on the calendar year.

Utilities that draw from the Wildfire Fund or the Continuation Account will only be required to reimburse amounts that are determined by the CPUC in a proceeding for cost recovery not to be just and reasonable, applying the prudency standard in AB 1054 and after allocating costs and expenses for cost recovery based on relevant factors both within and outside of a utility's control that may have exacerbated the costs and expenses. As amended by SB 254, the reimbursement requirement is subject to a disallowance cap equal to 20% of the equity portion of the utility's electric transmission and distribution rate base in the year of the ignition. A utility would not be required to reimburse the Wildfire Fund or the Continuation Account for disallowances that exceed the disallowance cap in the aggregate in a three calendar-year period. For the Continuation Account, the amount of reimbursement would also be reduced by the amount of contributions for which the utility has not claimed a reduction. For the Utility, the disallowance cap would be approximately $4.7 billion for 2025. This disallowance cap is based on the equity portion of the Utility's forecasted weighted-average 2025 electric transmission and distribution rate base, which is subject to adjustment based on changes in the Utility's electric transmission and distribution rate base. The disallowance cap is inapplicable in certain circumstances, including if the Wildfire Fund administrator determines that the electric utility company's actions or inactions that resulted in the applicable wildfire constituted "conscious or willful disregard for the rights and safety of others," or the electric utility company failed 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 or the Continuation Account, resulting in a draw-down of the Wildfire Fund or Continuation Account, as applicable.

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. The safety certification is separate from the CPUC's enforcement authority and does not preclude the CPUC from pursuing remedies for safety or other applicable violations.

The Wildfire Fund is expected to be capitalized with at least $21 billion through (i) a 15-year non-bypassable 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 the participating utilities for a 10-year period. If the administrator determines that additional annual contributions are necessary, the Continuation Account would be capitalized with up to $18 billion, of which $9 billion would be contributed through a non-bypassable charge from customers, $5.1 billion would be contributed by the utilities, and an additional $3.9 billion would be contributed by the utilities if the administrator determines that additional contributions are needed.

The Wildfire Fund and Continuation Account will only be available for payment of eligible claims so long as they have sufficient funds remaining. Such funds could be depleted more quickly than PG&E Corporation's and the Utility's 20-year estimate for the life of the Wildfire Fund, including as a result of claims made by California's other participating utilities. The Wildfire Fund is available to pay for the Utility's eligible claims arising between July 12, 2019, the effective date of AB 1054, and September 19, 2025, the effective date of SB 254. Payments for eligible claims arising between the effective date of AB 1054 and the Utility's emergence from Chapter 11 are subject to a limit of 40% of the allowed amount of such claims. The 40% limit does not apply to eligible claims that arise after the Utility's emergence from Chapter 11.

AB 1054 authorizes the payment of funds to a participating utility where that utility has demonstrated that it exercised reasonable business judgment in the valuation and payment of third-party claims.

PG&E Corporation and the Utility's Wildfire Fund recoveries are reflected in Wildfire-related claims, net of recoveries in the Consolidated Statements of Income to the extent PG&E Corporation and the Utility determine that it is probable the CPUC will conclude that the Utility's conduct was just and reasonable or when the Utility is not otherwise required to reimburse the Wildfire Fund.

As of December 31, 2025, PG&E Corporation and the Utility recorded $295 million and $4 million in Accounts receivable - Other and Other noncurrent assets, respectively, for Wildfire Fund receivables related to the 2021 Dixie fire. The following table presents changes in accrued Wildfire Fund recoveries, net of claim payments received from the Wildfire Fund, for the 2021 Dixie fire since December 31, 2024:

Wildfire Fund Receivable (in millions)	**2021 Dixie fire**
Balance at December 31, 2024	**$ 756**
Accrued Wildfire Fund recoveries	225
Claims paid by Wildfire Fund	(682)
Balance at December 31, 2025	**$ 299**

For more information, see Note 2 above.

Wildfire-Related Securities Litigation

As further described under the headings "Wildfire-Related Securities Claims in District Court" and "Wildfire-Related Securities Claims—Claims in the Bankruptcy Court Process," PG&E Corporation and the Utility face certain wildfire-related securities claims related to the 2017 Northern California wildfires and other claims related to the 2018 Camp fire and the PSPS program in the Chapter 11 Cases (i.e., the Subordinated Claims), and certain former directors, former officers, and underwriters of certain note offerings face wildfire-related securities claims in the District Court action. The claims described under the heading "Wildfire-Related Securities Claims in District Court" are referred to as the "Wildfire-Related Non-Bankruptcy Securities Claims" and collectively with the claims described under the heading "Wildfire-Related Securities Claims—Claims in the Bankruptcy Court Process" are referred to in this section as the "Wildfire-Related Securities Claims."

Based on the facts and circumstances available to PG&E Corporation and the Utility as of the date of this filing, PG&E Corporation believes it is probable that it will incur a loss in connection with these matters. PG&E Corporation has recorded a liability in the aggregate amount of $300 million, which represents its best estimate of probable losses for the Wildfire-Related Securities Claims. PG&E Corporation believes that it is reasonably possible that the amount of loss could be greater or less than the accrued estimated amount due to the number of plaintiffs and the complexity of the litigation.

Wildfire-Related Securities Claims in District Court

In June 2018, two purported securities class actions were filed in the District Court, naming PG&E Corporation and certain of its former officers as defendants, entitled *David C. Weston v. PG&E Corporation, et al.* and *Jon Paul Moretti v. PG&E Corporation, et al*. The complaints alleged material misrepresentations and omissions in various PG&E Corporation public disclosures related to, among other things, vegetation management and other issues connected to the 2017 Northern California wildfires. 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 the Public Employee Retirement Association of New Mexico ("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, including allegations regarding transmission line safety and the PSPS program.

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 named as defendants certain 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 was named as a defendant. The complaint asserted claims under Section 11 of the Securities Act of 1933, as amended, based on alleged 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. 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 certain former officers and directors and the underwriters. While PG&E Corporation and the Utility are also named as defendants, the claims against PG&E Corporation and the Utility may only be pursued in Bankruptcy Court. On October 24, 2024, the officer, director, and underwriter defendants filed renewed motions to dismiss the third amended complaint. On September 30, 2025, the District Court granted the motions to dismiss with leave to amend. On November 14, 2025, the plaintiffs filed a fourth amended consolidated class action complaint. On December 22, 2025, the officer, director, and underwriter defendants filed motions to dismiss the fourth amended complaint.

On January 10, 2026, PERA filed a motion for preliminary approval of a $100 million proposed settlement among PERA, the defendants, PG&E Corporation, and the Utility, to resolve the consolidated securities actions. The proposed settlement is subject to District Court approval. A hearing on the motion for preliminary approval in the District Court is scheduled for February 26, 2026. Putative class members would have the right to opt out of the proposed settlement.

On March 21, 2023, another group of shareholders filed a separate action in the District Court against certain former officers and directors, entitled *Orbis Capital Limited et al., v. Williams et al.*, alleging similar claims to those alleged in *In re PG&E Corporation Securities Litigation*.

Wildfire-Related Securities Claims—Claims in the Bankruptcy Court Process

PG&E Corporation and the Utility intend to resolve securities claims filed in the bankruptcy consistent with the Plan. These claims consist of pre-petition claims against PG&E Corporation or the Utility 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 United States Bankruptcy Code. The first category of claims consists of pre-petition claims arising from or related to the trading of 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 the trading of 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, these defenses may not prevail and proceeds from any insurance 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 engaged in settlement efforts with respect to the Subordinated Claims. All such settlements have been conditioned upon, among other things, resolution of that claimant's Wildfire-Related Non-Bankruptcy Securities Claims. If any of the Subordinated Claims are ultimately not settled, PG&E Corporation and the Utility expect that those 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. Such claims could 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 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.

On January 25, 2021, the Bankruptcy Court issued an order to approve procedures to help facilitate the resolution of the Subordinated Claims. The order, among other things, established procedures allowing 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.

PG&E Corporation and the Utility have worked to resolve the Subordinated Claims in accordance with procedures approved by the Bankruptcy Court, including by collecting 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 continue to prosecute omnibus objections with respect to certain of the Subordinated Claims and act under the procedures approved by the Bankruptcy Court to resolve the Subordinated Claims.

Indemnification Obligations

To the extent permitted by law, PG&E Corporation and the Utility have obligations to indemnify directors and officers for certain events or occurrences while a director or officer is or was serving in such capacity, which indemnification obligations may extend to the claims asserted against certain directors and officers in the securities class actions.

PG&E Corporation and the Utility additionally may have 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.

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 assessments of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involve 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'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.

CPUC Matters

Wildfire and Gas Safety Costs Interim Rate Relief Subject to Refund

On June 15, 2023, the Utility filed a WGSC application with the CPUC requesting cost recovery of approximately $2.5 billion of recorded expenditures related to wildfire mitigation costs and gas safety and electric modernization costs.

The recorded expenditures for wildfire mitigation consist of $726 million in expenses and $1.5 billion in capital expenditures and cover activities during the years 2020 to 2022. The recorded expenditures for gas safety and electric modernization consist of $120 million in expenses and $118 million in capital expenditures and cover activities during the years 2017 to 2022. If approved, the requested cost recovery would result in an aggregate revenue requirement of $688 million. The costs addressed in the WGSC application are incremental to those previously authorized in the Utility's 2020 GRC and other proceedings.

On March 7, 2024, the CPUC approved a final decision authorizing the Utility to recover $516 million in interim rates to be recovered over at least 12 months starting April 1, 2024. The remaining $172 million will be recovered to the extent it is approved after the CPUC issues a final decision. 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.

Other Matters

PG&E Corporation and the Utility are subject to various claims and lawsuits that separately are not considered material. Estimated liabilities for contingencies related to such matters totaled $151 million and $74 million as of December 31, 2025 and 2024, respectively. These amounts were included in Other current liabilities on the Consolidated Financial Statements. Included among these claims and lawsuits are the proofs of claim filed in the Chapter 11 Cases, except for proofs of claim discussed under "Wildfire-Related Securities Claims—Claims in the Bankruptcy Court Process" in Note 14 above. PG&E Corporation and the Utility have resolved a significant majority of the proofs of claim. PG&E Corporation and the Utility continue their review and analysis of certain remaining claims. 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.

Environmental Remediation Contingencies

Environmental remediation contingencies are contingent liabilities that arise from federal, state, or local regulations requiring the remediation of contamination in soil, sediment, groundwater, and surface water. 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 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. Where 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. Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primarily included in Noncurrent liabilities on the Consolidated Balance Sheets and is comprised of the following:

	Balance at	
(in millions)	**December 31, 2025**	**December 31, 2024**
Topock natural gas compressor station	$ 315	$ 294
Hinkley natural gas compressor station	99	97
Former MGP sites owned by the Utility or third parties (1)	715	782
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	71	76
Fossil fuel-fired generation facilities and sites (3)	17	18
Total environmental remediation liability	**$ 1,217**	**$ 1,267**

(1) Primarily driven by the following sites: San Francisco Beach Street, San Francisco Outside East Harbor, San Francisco East Harbor, San Francisco North Beach and San Francisco Fillmore Street.
(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 EPA under the Federal Resource Conservation and Recovery Act in addition to other state laws relating to hazardous substances. The Utility has a comprehensive program to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements.

The Utility's environmental remediation liability as of December 31, 2025, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations, but the Utility's actual costs could materially exceed its estimates. 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. As of December 31, 2025, the Utility expected to recover $1.0 billion of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

The table below presents the high end of the range for the Utility's potential losses and whether HSMA recovery is available.

	Balance at December 31, 2025		
(in millions)	Low end of the range	High end of the range	HSMA Recovery (1)
Topock natural gas compressor station (2)	$ 315	$ 518	Available
Hinkley natural gas compressor station (2)	99	221	Unavailable
Former MGP sites owned by the Utility or third parties (3)	715	1,292	Available
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (4)	71	146	Available
Fossil fuel-fired generation facilities and sites (5)	17	32	Unavailable

(1) For sites where HSMA recovery is available, the Utility expects to recover 90% of the costs associated with environmental remediation through rates.
(2) 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. At the Topock site, the Utility completed the initial phase of construction on an in-situ groundwater treatment system in 2021, and additional construction will continue for several years.
(3) 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.
(4) Utility-owned generation facilities and third-party disposal sites often involve long-term remediation.
(5) The Utility sold its fossil-fueled generation power plants in 1998 but retains the environmental remediation liability associated with each site.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL, a mutual insurer owned by utilities with nuclear facilities, and European Mutual Association for Nuclear Insurance ("EMANI"), covering nuclear or non-nuclear events at the Utility's two nuclear generating units at DCPP and the Humboldt Bay independent spent fuel storage installation.

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 DCPP. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.5 billion per non-nuclear incident for DCPP. For Humboldt Bay independent spent fuel storage installation, 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 and cyberattacks at nuclear power plants. Through NEIL, there is up to $3.2 billion available to the membership to cover this exposure. These coverage amounts are shared by all NEIL members and all nuclear and non-nuclear property insurance policies issued by NEIL. EMANI shares losses with NEIL as part of the first $400 million of coverage within the current nuclear insurance program. EMANI also provides an additional $200 million in excess insurance for property damage and business interruption losses incurred by the Utility if a nuclear or non-nuclear event were to occur at DCPP. If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, the maximum aggregate annual retrospective premium obligation for the Utility would be approximately $43 million.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at DCPP, and that occur during the transportation of material to and from DCPP are limited to approximately $16.3 billion. The Utility purchases the maximum available public liability insurance of $500 million for DCPP. The balance of the $16.3 billion of liability protection is provided under a loss-sharing program among nuclear reactor owners. The Utility may be assessed up to $332 million per nuclear incident under this loss sharing program, with payments in each year limited to a maximum of $49 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 $500 million per incident. In addition, the Utility has approximately $53 million of liability insurance for the Humboldt Bay independent spent fuel storage installation and has a $500 million indemnification from the NRC for public liability arising from nuclear incidents for the Humboldt Bay independent spent fuel storage installation, covering liabilities in excess of the $53 million in liability insurance.

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, 2025:

	Power Purchase Agreements				
(in millions)	**Renewable Energy**	**Conventional Energy**	**Natural Gas**	**Other [(1)]**	**Total**
2026	$ 1,937	$ 1,058	$ 544	$ 278	$ 3,817
2027	1,921	1,035	193	134	3,283
2028	1,903	989	106	47	3,045
2029	1,858	905	98	6	2,867
2030	1,852	510	42	2	2,406
Thereafter	12,828	4,315	34	5	17,182
Total purchase commitments	**$ 22,299**	**$ 8,812**	**$ 1,017**	**$ 472**	**$ 32,600**

(1) Includes other power purchase agreements and nuclear fuel agreements.

Third-Party Power Purchase Agreements

In the ordinary course of business, the Utility enters into various agreements, including renewable energy agreements, qualifying facilities ("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. These renewable energy contracts expire at various dates between 2026 and 2047.

Conventional Energy Power Purchase Agreements

The Utility has entered into many power purchase agreements for conventional generation resources, which include a tolling agreement 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 2026 and 2044.

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, 2025, QF contracts in operation expire at various dates between 2026 and 2049. In addition, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The net costs incurred for all power purchases and electric capacity were $2.0 billion in 2025, $2.1 billion in 2024, and $2.4 billion in 2023.

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 along with a facility associated with a third party tolling agreement. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the United States 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 2026 and 2035. In addition, the Utility has contracted for natural gas storage services in Northern California and Canada 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, were $1.0 billion in 2025, $0.8 billion in 2024, and $2.5 billion in 2023.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2026 and 2030 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 were $134 million in 2025, $294 million in 2024, and $180 million in 2023.

Other Commitments

PG&E Corporation and the Utility have other commitments primarily related to office facilities leases and land leases which expire at various dates between 2026 and 2054, as well as other multi-year agreements. At December 31, 2025, the future minimum payments related to these commitments were as follows:

(in millions)	**Other Commitments**
2026	$ 82
2027	51
2028	41
2029	39
2030	13
Thereafter	65
Total minimum payments	**$ 291**

Payments for other commitments were $63 million in 2025, $105 million in 2024, and $106 million in 2023. 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.

In addition to the commitments in the table above, if the CPUC determines that it is needed, the Utility will make a supplemental shareholder contribution to the customer credit trust of up to $775 million in 2040. The Utility also will share with customers 25% of any surplus of shareholder assets in the customer credit trust at the end of the life of the trust.

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 (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). 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, 2025, 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, 2025.

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, 2025, 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, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 11, 2026, 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 U.S. 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 Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulation and Regulated Operations—Refer to Notes 2, 3 and 14 to the financial statements

Critical Audit Matter Description

The Company’s subsidiary, Pacific Gas and 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 Utility Commission (the “CPUC”) or the Federal Energy Regulatory Commission (the “FERC”) based on its cost of providing service. Pacific Gas and Electric Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under accounting principles generally accepted in the United States of America (“GAAP”) for nonregulated entities. Pacific Gas and 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, specifically costs subject to cost recovery proceedings that have not yet been approved, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the significant 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 significant degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions.

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 included the following, among others:

- We tested the effectiveness of controls over (1) the evaluation of the likelihood of (a) the recovery of costs deferred as regulatory assets in future rates; 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 subject to cost recovery proceedings that have not yet been approved for recovery, 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 and FERC 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 and FERC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset balances for completeness.

- We inspected Pacific Gas and Electric Company's filings with the CPUC and FERC and the filings with the CPUC and FERC by intervenors that may impact 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 were appropriate and consistent with the information obtained from our procedures performed.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 11, 2026

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, 2025 and 2024, 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, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 11, 2026, 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 U.S. 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 Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulation and Regulated Operations—Refer to Notes 2, 3 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 Utility Commission (the "CPUC") or the Federal Energy Regulatory Commission (the "FERC") 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 accounting principles generally accepted in the United States of America ("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, specifically costs subject to cost recovery proceedings that have not yet been approved, as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the significant 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 significant degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions.

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 included the following, among others:

- We tested the effectiveness of controls over (1) the evaluation of the likelihood of (a) the recovery of costs deferred as regulatory assets in future rates; 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 subject to cost recovery proceedings that have not yet been approved for recovery, 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 and FERC 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 and FERC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset balances for completeness.

- We inspected the Utility's filings with the CPUC and FERC and the filings with the CPUC and FERC by intervenors that may impact 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 were appropriate and consistent with the information obtained from our procedures performed.

/s/ DELOITTE & TOUCHE LLP
San Francisco, California
February 11, 2026

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, 2025, 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, 2025, 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, 2025, of the Company and our report dated February 11, 2026, 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 11, 2026

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, 2025, 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, 2025, 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, 2025, of the Utility and our report dated February 11, 2026, 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 11, 2026

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 defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2025, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective as of such date 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 Exchange 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 2025 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, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. See "Report of Independent Registered Public Accounting Firm" in Part II, Item 8 of this 2025 Form 10-K.

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, 2025 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

On November 3, 2025, John R. Simon, who serves as the Executive Vice President, General Counsel and Chief Ethics and Compliance Officer of PG&E Corporation, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) under the Exchange Act, for the sale of up to 50,000 shares of PG&E Corporation common stock. The trading arrangement will terminate on the earlier of August 1, 2026 or the execution of the sale of all 50,000 shares.

On November 4, 2025, Patricia K. Poppe, who serves as the Chief Executive Officer of PG&E Corporation, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense conditions of Rule 10b5-1(c), for the sale of up to 62,500 shares of PG&E Corporation common stock. The trading arrangement will terminate on the earlier of July 31, 2026 or the execution of the sale of all 62,500 shares.

On November 13, 2025, Sumeet Singh, who serves as the Chief Executive Officer, Pacific Gas and Electric Company, and Executive Vice President, Energy Delivery of the Utility, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense conditions of Rule 10b5-1(c), for the sale of an indeterminate number of shares of PG&E Corporation common stock. The number of shares that may be sold under this Rule 10b5-1 trading arrangement will vary based on the number of shares that Mr. Singh receives when his performance share units ("PSUs") vest. Assuming that the PSUs vest at 100% of target, this Rule 10b5-1 plan would entail the sale of 52,450 shares, but the actual number could vary based on the number of PSUs that vest. In addition, the maximum number of shares to be sold will be reduced by shares withheld to satisfy tax withholding obligations that arise in connection with the vesting and settlement. The trading arrangement will terminate on the earlier of May 15, 2026 or the execution of the sale of all covered shares.

On November 25, 2025, Kerry W. Cooper, who serves as the Chair of the Board of PG&E Corporation, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense conditions of Rule 10b5-1(c), for the sale of up to 10,000 shares of PG&E Corporation common stock. The trading arrangement will terminate on the earlier of December 31, 2026 or the execution of the sale of all 10,000 shares.

On December 11, 2025, Carla J. Peterman, who serves as the President, PG&E Corporation, and Executive Vice President, Customer & Corporate Affairs of PG&E Corporation, adopted a Rule 10b5-1 trading arrangement that is intended to satisfy the affirmative defense conditions of Rule 10b5-1(c), for the sale of an indeterminate number of shares of PG&E Corporation common stock. The number of shares that may be sold under this Rule 10b5-1 trading arrangement will vary based on the number of shares that Ms. Peterman receives when her PSUs vest. Assuming that the PSUs vest at 100% of target, this Rule 10b5-1 plan would entail the sale of 96,095 shares, but the actual number could vary based on the number of PSUs that vest. In addition, the maximum number of shares to be sold will be reduced by shares withheld to satisfy tax withholding obligations that arise in connection with the vesting and settlement. The trading arrangement will terminate on the earlier of November 30, 2026 or the execution of the sale of all covered shares.

Certain officers have made elections to participate in, and are participating in, the PG&E Corporation Retirement Savings Plan, which includes a PG&E Corporation Common Stock Fund investment option, and non-qualified deferred compensation plans, which may have a similar option and are described in PG&E Corporation's and the Utility's joint proxy statement. Also, certain officers have made, and may from time to time make, elections to have shares withheld to cover withholding taxes upon the vesting of restricted stock units or performance share units, or to pay the exercise price and withholding taxes for stock options, which may be designed to satisfy the affirmative defense conditions of Rule 10b5-1(c) or may constitute "non-Rule 10b5-1 trading arrangements" (as defined in Item 408(c) of Regulation S-K).

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 2025 Form 10-K.

PG&E Corporation and the Utility have adopted insider trading policies and procedures governing the purchase, sale, and/or other dispositions of their securities by directors, officers, and employees. PG&E Corporation and the Utility have a policy of not issuing or purchasing securities while in possession of material nonpublic information but do not have written procedures for the repurchase of their securities. PG&E Corporation and the Utility believe their insider trading policies and procedures are reasonably designed to promote compliance with insider trading laws, rules, and regulations, and applicable listing standards. A copy of the insider trading policy is filed as Exhibit 19 to this Form 10-K.

Other information required by this Item 10 will be included in the Joint Proxy Statement relating to the 2026 Annual Meetings of Shareholders to be filed with the SEC within 120 days after the companies' fiscal year end of December 31, 2025 under the headings "Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" (under the subheadings "Nominees," "Committee Responsibilities," "Committee Membership Requirements," and "Delinquent Section 16(a) Reports,") and "User Guide" (under the subheading "2026 Annual Meetings,") which information is incorporated herein by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

PG&E Corporation and the Utility have adopted the following documents:

- A Code of Conduct applicable to all officers and employees;
- A Code of Conduct applicable to directors;
- A Code of Conduct applicable to suppliers and contractors;
- Corporate Governance Guidelines (separate guidelines for PG&E Corporation and the Utility); and
- Charters for committees of the Board, including charters for the Audit Committees, the PG&E Corporation Sustainability and Governance Committee, the PG&E Corporation Finance and Innovation Committee and the PG&E Corporation People and Compensation Committee.

Each of these documents is available on PG&E Corporation's website at https://www.pgecorp.com/about/corporate-governance.html or https://www.pgecorp.com/about/compliance-and-ethics.html.

Any amendment to or waiver from either Code of Conduct that applies to the respective executive officers or directors of PG&E Corporation or the Utility will be posted on PG&E Corporation's website, www.pgecorp.com.

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 - 2025," "Grants of Plan-Based Awards in 2025," "Outstanding Equity Awards at Fiscal Year End - 2025," "Option Exercises and Stock Vested during 2025," "Pension Benefits - 2025," "Non-Qualified Deferred Compensation - 2025," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability," "Compensation of Non-Employee Directors," and "Principal Executive Officers' (PEO) Pay Ratio - 2025," in the Joint Proxy Statement relating to the 2026 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 will be 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 2026 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2025 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	22,859,547 [1]	$ 41.27 [2]	51,401,320 [3]
Equity compensation plans not approved by shareholders	—	—	—
Total equity compensation plans	22,859,547 [1]	$ 41.27 [2]	51,401,320 [3]

[1] Includes 162 phantom stock units, 10,842,071 restricted stock units and 11,384,846 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 for operational and financial metrics or, for performance shares granted in 2022, amounts reflect the estimated payout percentage of 110% for performance shares using operational and financial metrics, and 200% of target for the total shareholder return metric. The actual number of shares issued can range from zero percent to 200% of target depending on achievement of performance objectives. 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 632,468 options outstanding as of December 31, 2025.

[3] Represents the total number of shares available for issuance under all PG&E Corporation's equity compensation plans as of December 31, 2025. Stock-based awards granted under these plans include restricted stock units, performance shares, stock options, and phantom stock units. The PG&E Corporation 2014 LTIP, which became effective on May 12, 2014, authorized 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 LTIP at December 31, 2013, or awards granted under the PG&E Corporation 2006 LTIP 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 PG&E Corporation 2014 LTIP on July 1, 2020, as part of the Plan. Lastly, an additional 44 million shares were authorized for issuance under the PG&E Corporation 2021 LTIP 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 Person Transactions," "Independence," and "Committee Membership Requirements" in the Joint Proxy Statement relating to the 2026 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 2026 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, 2025, 2024, and 2023 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2025 and 2024 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2025, 2024, and 2023 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2025, 2024, and 2023 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:

Consolidated Financial Information of PG&E Corporation ("Parent") as of December 31, 2025 and 2024 and for the Years Ended December 31, 2025, 2024, and 2023.

Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2025, 2024, and 2023.

3. Exhibits required by Item 601 of Regulation S-K

Exhibit Number	Exhibit Description
3.1	Conformed Version of Amended and Restated Articles of Incorporation of PG&E Corporation, filed June 22, 2020, as amended by the Certificate of Amendment of Articles of Incorporation of PG&E Corporation, filed May 24, 2022 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2022 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination of 6.000% Series A Mandatory Convertible Preferred Stock of PG&E Corporation, filed with the Secretary of State of the State of California and effective as of December 5, 2024 (incorporated by reference to PG&E Corporation's Form 8-K dated December 2, 2024 (File No. 1-12609) , Exhibit 3.1)
3.3	Bylaws of PG&E Corporation, Amended and Restated as of December 12, 2024 (incorporated by reference to PG&E Corporation's Form 8-K dated December 12, 2024 (File No. 1-12609), Exhibit 3.1)
3.4	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)

3.5	Bylaws of Pacific Gas and Electric Company, Amended and Restated as of December 11, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 11, 2025 (File No. 1-2348), Exhibit 3.1)
4.1 (a)	Description of PG&E Corporation's Securities - Common Stock and Preferred Stock
4.1 (b)	Description of Pacific Gas and Electric Company's Securities - Preferred Stock
4.1 (c)	Form of Certificate for 6.000% Series A Mandatory Convertible Preferred Stock (included within Exhibit 3.2 above) (incorporated by reference to PG&E Corporation's Form 8-K dated December 2, 2024 (File No. 1-2609), Exhibit 3.1)
4.2	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004 (as supplemented) 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)
4.2.1	Sixteenth Supplemental Indenture, dated as of December 1, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
4.2.2	Seventeenth Supplemental Indenture, dated as of April 16, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.2.3	Eighteenth Supplemental Indenture, dated as of August 16, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.2.4	Nineteenth Supplemental Indenture, dated as of June 14, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)
4.2.5	Twenty-First Supplemental Indenture, dated as of February 21, 2014 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No. 1-2348), Exhibit 4.1)
4.2.6	Twenty-Third Supplemental Indenture, dated as of August 18, 2014 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1-2348), Exhibit 4.1)
4.2.7	Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1-2348), Exhibit 4.1)
4.2.8	Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1)
4.2.9	Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1)
4.2.10	Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1)
4.2.11	Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1)
4.2.12	Twenty-Ninth Supplemental Indenture, dated as of March 10, 2017 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 10, 2017 (File No. 1-2348), Exhibit 4.1)
4.2.13	Thirtieth Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.3)
4.3	Indenture, dated as of November 29, 2017, 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 November 29, 2017 (File No. 1-2348), Exhibit 4.1)
4.3.1	First Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.4)
4.4	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)

4.4.1	First Supplemental Indenture, dated as of August 6, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 6, 2018 (File No. 1-2348), Exhibit 4.2)
4.4.2	Second Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated July 2, 2020 (File No. 1-2348), Exhibit 4.5)
4.5	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)
4.5.1	First Supplemental Indenture, dated as of June 19, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 19, 2020 (File No. 1-2348), Exhibit 4.2)
4.5.2	Second Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.6)
4.5.3	Third Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.1)
4.5.4	Fourth Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.2)
4.5.5	Fifth Supplemental Indenture, dated as of July 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 30, 2020 (File No. 1-2348), Exhibit 4.7)
4.5.6	Sixth Supplemental Indenture, dated as of August 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2020 (File No. 1-2348), Exhibit 4.15)
4.5.7	Eighth Supplemental Indenture, dated as of March 11, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 8, 2021 (File No. 1-2348), Exhibit 4.1)
4.5.8	Ninth Supplemental Indenture, dated as of June 3, 2021, to the Indenture of Mortgage (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2021 (File No. 12348), Exhibit 4.1)
4.5.9	Tenth Supplemental Indenture, dated as of June 22, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2021 (File No. 1-2348), Exhibit 4.1)
4.5.10	Eleventh Supplemental Indenture, dated as of October 29, 2021 (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)
4.5.11	Twelfth Supplemental Indenture, dated as of November 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 10, 2021 (File No. 1-2348), Exhibit 4.1)
4.5.12	Thirteenth Supplemental Indenture, dated as of February 18, 2022 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 16, 2022 (File No. 1-2348), Exhibit 4.1)
4.5.13	Fourteenth Supplemental Indenture, dated as of April 4, 2022 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 4, 2022 (File No. 1-2348), Exhibit 4.1)
4.5.14	Fifteenth Supplemental Indenture, dated as of April 20, 2022 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 20, 2022 (File No. 1-2348), Exhibit 4.1)
4.5.15	Sixteenth Supplemental Indenture, dated as of June 8, 2022 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 6, 2022 (File No. 1-2348), Exhibit 4.1)
4.5.16	Seventeenth Supplemental Indenture, dated as of October 4, 2022 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2022 (File No. 1-2348), Exhibit 4.3)
4.5.17	Eighteenth Supplemental Indenture, dated as of January 6, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 4, 2023 (File No. 1-2348), Exhibit 4.1)
4.5.18	Nineteenth Supplemental Indenture, dated as of March 30, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 28, 2023 (File No. 1-2348), Exhibit 4.1)
4.5.19	Twentieth Supplemental Indenture, dated as of June 5, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 1, 2023 (File No. 1-2348), Exhibit 4.1)

4.5.20	Twenty-First Supplemental Indenture, dated as of November 8, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2023 (File No. 1-2348), Exhibit 4.1)
4.5.21	Twenty-Second Supplemental Indenture, dated as of November 15, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 15, 2023 (File No. 1-2348), Exhibit 4.1)
4.5.22	Twenty-Third Supplemental Indenture, dated as of December 21, 2023 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2023 (File No. 1-2348, Exhibit 4.5.22)
4.5.23	Twenty-Fourth Supplemental Indenture, dated as of February 28, 2024 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 26, 2024 (File No. 1-2348), Exhibit 4.1)
4.5.24	Twenty-Fifth Supplemental Indenture, dated as of September 5, 2024 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 3, 2024 (File No. 1-2348), Exhibit 4.1)
4.5.25	Twenty-Sixth Supplemental Indenture, dated as of January 17, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 17, 2025 (File No. 1-2348), Exhibit 4.1)
4.5.26	Twenty-Seventh Supplemental Indenture, dated as of February 20, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2025 (File No. 1-2348), Exhibit 4.4)
4.5.27	Twenty-Eighth Supplemental Indenture, dated as of February 26, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 24, 2025 (File No. 1-2348), Exhibit 4.1)
4.5.28	Twenty-Ninth Supplemental Indenture, dated as of June 4, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 2, 2025 (File No. 1-2348), Exhibit 4.1)
4.5.29	Thirtieth Supplemental Indenture, dated as of September 24, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 24, 2025 (File No. 1-2348), Exhibit 4.1)
4.5.30	Thirty-First Supplemental Indenture, dated as of October 2, 2025 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 30, 2025 (File No. 1-12609), Exhibit 4.1)
4.5.31	Thirty-Second Supplemental Indenture, dated as of November 14, 2025
4.6	Note Purchase Agreement dated January 17, 2025, among Pacific Gas and Electric Company, the U.S. Department of Energy, acting by and through the Secretary of Energy, and the Federal Financing Bank (redacted) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 17, 2025 (File No. 1-2348), Exhibit 4.2)
4.6.1	Future Advance Promissory Note dated January 17, 2025, made by Pacific Gas and Electric Company to the Federal Financing Bank (redacted) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 17, 2025 (File No. 1-2348), Exhibit 4.3)
4.7	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)
4.7.1	First Supplemental Indenture, dated as of June 23, 2020 (incorporated by reference to PG&E Corporation's Form 8-K dated June 19, 2020 (File No. 1-2609), Exhibit 4.2)
4.8	Indenture, dated as of December 4, 2023, among PG&E Corporation, The Bank of New York Mellon Trust Company, N.A., as trustee and JPMorgan Chase Bank, N.A., as collateral agent (incorporated by reference to PG&E Corporation's Form 8-K dated December 4, 2023 (File No. 1-12609), Exhibit 4.1)
4.9	Subordinated Note Indenture, dated as of September 11, 2024, 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 September 9, 2024 (File No. 1-12609), Exhibit 4.1)
4.9.1	First Supplemental Indenture, dated as of September 11, 2024 (incorporated by reference to PG&E Corporation's Form 8-K dated September 9, 2024 (File No. 1-12609), Exhibit 4.2)

10.1	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)
10.2	Credit Agreement, dated as of July 1, 2020, 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 PG&E Corporation's Form 8-K dated June 30, 2020 (File No. 1-12609), Exhibit 10.3)
10.2.1	Amendment No. 1 to Credit Agreement, dated as of June 22, 2021, among PG&E Corporation, the several banks and other financial institutions or entities party thereto from time to time, JPMorgan 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)
10.2.2	Amendment No. 2 to Credit Agreement, dated as of October 4, 2022, among PG&E Corporation, the lenders party thereto 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, 2022 (File No. 1-12609), Exhibit 10.2)
10.2.3	Amendment No. 3 to Credit Agreement, dated as of June 22, 2023, among PG&E Corporation, the several banks and other financial institutions or entities party thereto from time to time and JPMorgan Chase Bank, N.A., administrative agent (incorporated by reference to PG&E Corporation's Form 8-K dated June 22, 2023 (File No. 1-12609), Exhibit 10.1)
10.2.4	Amendment No. 4 to Credit Agreement, dated as of July 25, 2024, among PG&E Corporation, the lenders party thereto, 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, 2024 (File No. 1-12609), Exhibit 10.6)
10.2.5	Amendment No. 5 to Credit Agreement, dated as of June 23, 2025, among PG&E Corporation, 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 8-K dated June 23, 2025 (File No. 1-2348), Exhibit 10.2)
10.3	Pledge Agreement, dated as of July 1, 2020, 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 part 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)
10.4	Credit Agreement, dated as of July 1, 2020, 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)
10.4.1	Amendment No. 1 to Credit Agreement, dated as of June 22, 2021, among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time, 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 22, 2021 (File No. 1-2348), Exhibit 10.2)
10.4.2	Amendment No. 2 to Credit Agreement, dated as of October 4, 2022, among Pacific Gas and Electric Company, the lenders party thereto, Citibank, N.A., as administrative agent and Citibank, N.A., as designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2022 (File No. 1-2348), Exhibit 10.3)
10.4.3	Amendment No. 3 to Credit Agreement, dated as of June 22, 2023, among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time and Citibank, N.A., as administrative agent and designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 22, 2023 (File No. 1-2348), Exhibit 10.2)
10.4.4	Amendment No. 4 to Credit Agreement, dated as of July 25, 2024, among Pacific Gas and Electric Company, the lenders party thereto, Citibank, N.A., as administrative agent and designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2024 (File No. 1-12609), Exhibit 10.5)
10.4.5	Amendment No. 5 to Credit Agreement, dated as of June 23, 2025, among Pacific Gas and Electric Company, the several banks and other financial institutions or entities party thereto from time to time and Citibank N.A., as administrative agent and designated agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 23, 2025 (File No. 1-2348), Exhibit 10.1)

10.5	Term Loan Credit Agreement, dated as of September 24, 2025, among Pacific Gas and Electric Company, the several lenders from time to time parties thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 24, 2025 (File No. 1-2348), Exhibit 10.1)
10.6	Term Loan Credit Agreement, dated as of April 20, 2022, among Pacific Gas and Electric Company, the several lenders from time to time parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 20, 2022 (File No. 1-2348), Exhibit 10.1)
10.6.1	Amendment No. 1 to Credit Agreement, dated as of September 23, 2022, among Pacific Gas and Electric Company, the several lenders from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2022 (File No. 1-2348) Exhibit (10.37)
10.6.2	Amendment No. 2 to Credit Agreement, dated as of April 18, 2023, among Pacific Gas and Electric Company, the several lenders from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2023 (File No. 1-2348) Exhibit 10.3)
10.6.3	Amendment No. 3 to Credit Agreement, dated as of April 16, 2024, among Pacific Gas and Electric Company, the lenders party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-2348) Exhibit 10.1)
10.6.4	Amendment No. 4 to Credit Agreement, dated as of April 11, 2025, among Pacific Gas and Electric Company, the lenders party thereto, and Bank of America, N.A., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2025 (File No. 1-12348), Exhibit 10.2)
10.6.5	Amendment No. 5 to Credit Agreement, dated as of December 19, 2025, among Pacific Gas and Electric Company, the lenders party thereto, and Bank of America, N.A., as administrative agent
10.7	Purchase and Sale Agreement, dated as of October 5, 2020, 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 Pacific Gas and Electric Company's Form 8-K dated October 5, 2020 (File No. 1-2348), Exhibit 10.1)
10.7.1	Amendment No. 1 to Purchase and Sale Agreement, dated as of January 14, 2021, 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 Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2020 (File No. 1-2348), Exhibit 10.75)
10.7.2	Amendment No. 2 to Purchase and Sale Agreement, dated as of March 18, 2022, among PG&E AR Facility, LLC, as buyer, Pacific Gas and Electric Company, as initial servicer and originator, JPMorgan Chase Bank, N.A., as a committed lender and group agent, Jupiter Securitization Company LLC, as a conduit lender, Mizuho Bank, Ltd., as a committed lender and group agent, BNP Paribas, as a committed lender and group agent, Starbird Funding Corporation, as a conduit lender, Victory Receivables Corporation, as a conduit lender, and MUFG Bank, Ltd., as a committed lender, group agent and administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2022 (File No. 1-2348), Exhibit 10.2)
10.7.3	Amendment No. 3 to Purchase and Sale Agreement, dated as of April 20, 2022, among PG&E AR Facility, LLC, as buyer, Pacific Gas and Electric Company, as initial servicer and as an originator, the financial institutions party thereto and listed therein as committed lenders, conduit lenders, and group agents, and MUFG Bank, Ltd., as a Committed Lender, a Group Agent, and MUFG Bank, Ltd., administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 20, 2022 (File No. 1-2348), Exhibit 10.3)
10.8	Receivables Financing Agreement, dated as of October 5, 2020, 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 Pacific Gas and Electric Company's Form 8-K dated October 5, 2020 (File No. 1-2348), Exhibit 10.2)

10.8.1	Amendment No. 1 to Receivables Financing Agreement, dated as of January 14, 2021, 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 Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2020 (File No. 1-2348), Exhibit 10.77)
10.8.2	Amendment No. 2 to Receivables Financing Agreement, dated as of February 12, 2021, 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 Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2020 (File No. 1-2348), Exhibit 10.78)
10.8.3	Amendment No. 3 to Receivables Financing Agreement, dated as of May 5, 2021, 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 Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-2348), Exhibit 10.2)
10.8.4	Amendment No. 4 to Receivables Financing Agreement, dated as of September 15, 2021, 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 Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2021 (File No. 1-2348), Exhibit 10.3)
10.8.5	Amendment No. 5 to Receivables Financing Agreement, dated as of March 18, 2022, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2022 (File No. 1-2348), Exhibit 10.4)
10.8.6	Amendment No. 6 to Receivables Financing Agreement, dated as of April 20, 2022, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 20, 2022 (File No. 1-2348), Exhibit 10.2)
10.8.7	Amendment No. 7 to Receivables Financing Agreement and Limited Waiver, dated as of June 21, 2022, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2022 (File No. 1-2348), Exhibit 10.6)
10.8.8	Amendment No. 8 to Receivables Financing Agreement, dated as of September 30, 2022, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2022 (File No. 1-2348), Exhibit 10.7)
10.8.9	Amendment No. 9 to Receivables Financing Agreement, dated as of June 9, 2023, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2023 (File No. 1-2348), Exhibit 10.3)
10.8.10	Amendment No. 10 to Receivables Financing Agreement, dated as of December 8, 2023, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-2348), Exhibit 10.2)
10.8.11	Amendment No. 11 to Receivables Financing Agreement, dated as of March 28, 2024, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-2348), Exhibit 10.3)

10.8.12		Amendment No. 12 to Receivables Financing Agreement, dated as of June 26, 2024, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2024 (File No. 1-2348), Exhibit 10.2)
10.8.13		Amendment No. 13 to Receivables Financing Agreement, dated as of June 26, 2025, among PG&E AR Facility, LLC, as borrower, Pacific Gas and Electric Company, in its capacity as initial servicer, the financial institutions from time to time party thereto and listed therein as lenders and MUFG Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2025 (File No. 1-2348), Exhibit 10.4)
10.9		Pledge Agreement, dated as of October 5, 2020, between Pacific Gas and Electric Company and MUFG Bank, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 5, 2020 (File No. 1-2348), Exhibit 4.1)
10.10		Collection Account Intercreditor Agreement, dated as of October 5, 2020, 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 Pacific Gas and Electric Company's Form 8-K dated October 5, 2020 (File No. 1-2348), Exhibit 10.3)
10.10.1		Update to Schedule 1 to Collection Account Intercreditor Agreement, dated as of March 28, 2024, among Pacific Gas and Electric Company, PG&E Recovery Funding LLC, PG&E Wildfire Recovery Funding LLC, Citibank, N.A., MUFG Bank Ltd., and The Bank of New York Mellon Trust Company, N.A. (redacted) (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-2348) Exhibit 10.4)
10.10.2		Joinder Agreement to Collection Account Intercreditor Agreement, dated as of August 1, 2024, among Pacific Gas and Electric Company, Citibank, N.A., in its role as collection account agent and PG&E Recovery Funding LLC (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 1, 2024 (File No. 1-2348), Exhibit 10.4)
10.11		Loan Guarantee Agreement, dated as of January 17, 2025, between Pacific Gas and Electric Company and the U.S. Department of Energy, acting by and through the Secretary of Energy (redacted) (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated January 17, 2025 (File No. 1-2348), Exhibit 10.1)
10.12	*	Retention Letter Agreement, dated as of February 20, 2024, between PG&E Corporation and Carla J. Peterman (redacted) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-12609), Exhibit 10.5)
10.13	*	Retention Letter Agreement, dated as of February 20, 2024, between PG&E Corporation and John R. Simon (redacted) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2024 (File No. 1-12609), Exhibit 10.6)
10.14	*	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)
10.15	*	Amendment to Offer Letter, between PG&E Corporation and Patricia K. Poppe, dated as of November 29, 2024 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated November 29, 2024 (File No. 1-2609) (File No. 1-2348), Exhibit 10.1)
10.16	*	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective as of September 12, 2023 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2023 (File No. 1-12609), Exhibit 10.5)
10.17	*	PG&E Corporation Supplemental Retirement Savings Plan, as amended effective as of September 12, 2023, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2023 (File No. 1-12609), Exhibit 10.2)
10.18	*	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective as of May 14, 2024 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2024 (File No. 1-12609), Exhibit 10.4)
10.19	*	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of September 12, 2023 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2023 (File No. 1-12609), Exhibit 10.4)
10.20	*	PG&E Corporation 2012 Officer Severance Policy, as amended effective as of September 12, 2023 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2023 (File No. 1-12609), Exhibit 10.30)

10.21	*	PG&E Corporation Short-Term Incentive Plan, as amended effective as of May 16, 2023 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2023 (File No. 1-12609), Exhibit 10.8)
10.22	*	Pacific Gas and Electric Company Officer Relocation Guide, effective as of May 1, 2022
10.23	*	Postretirement Life Insurance Plan of Pacific Gas and Electric Company, as amended and restated as of 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)
10.23.1	*	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective as of 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)
10.23.2	*	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective as of February 16, 2016, (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-2348), Exhibit 10.4)
10.23.3	*	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective as of January 1, 2019 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2020 (File No. 1-2348), Exhibit 10.100)
10.23.4	*	Amendment to the Postretirement Life Insurance Plan of Pacific Gas and Electric Company, effective as of January 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2022 (File No. 1-12609), Exhibit 10.77)
10.24	*	PG&E Corporation 2014 Long-Term Incentive Plan (as adopted effective May 12, 2014 and as last amended effective as of July 1, 2020) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2020 (File No. 112609), Exhibit 10.40)
10.25	*	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)
10.26	*	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)
10.27	*	PG&E Corporation 2021 Long-Term Incentive Plan, as amended effective as of May 22, 2025 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2025 (File No. 1-12609), Exhibit 10.5)
10.28	*	Form of Restricted Stock Unit Agreement for 2022 grants to Non-Employee Directors under the PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2022 (File No. 1-12609), Exhibit 10.11)
10.29	*	Form of Restricted Stock Unit Agreement for 2023 grants to Non-employee Directors under the PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2023 (File No. 1-12609), Exhibit 10.9)
10.30	*	Form of Restricted Stock Unit Agreement for 2024 grants to Non-Employee Directors under the PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2024 (File No. 1-12609), Exhibit 10.5)
10.31	*	Form of Restricted Stock Unit Agreement for 2025 grants to Non-Employee Directors under the PG&E Corporation 2021 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2025 (File No. 1-12609), Exhibit 10.6)
10.32	*	Form of PG&E Corporation 2021 Long-Term Incentive Plan Restricted Stock Unit Award, as amended effective as of August 14, 2022
10.33	*	Form of PG&E Corporation 2021 Long-Term Incentive Plan Non-Annual Restricted Stock Unit Award, as amended effective as of August 14, 2022 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2022 (File No. 1-12609), Exhibit 10.8)
10.34	*	Form of PG&E Corporation 2021 Long-Term Incentive Plan Non-Annual Program-Specific Retention Stock Unit Award Agreement, effective September 17, 2024 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2024 (File No. 1-12609), Exhibit 10.7)

10.35	*	Form of PG&E Corporation 2021 Long-Term Incentive Plan Non-Annual Program-Specific Retention Stock Unit Award Agreement, effective February 19, 2025 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2025 (File No. 1-12609), Exhibit 10.4)
10.36	*	Amendment to 2014 PG&E Corporation Long-Term Incentive Plan Award Agreements and 2021 PG&E Corporation Long-Term Incentive Plan Award Agreements, dated as of August 14, 2022 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2022 (File No. 1-12609), Exhibit 10.11)
10.37	*	Form of Consent to Amend Award Agreement under the 2014 PG&E Corporation Long-Term Incentive Plan and/or 2021 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2023 (File No. 112609), Exhibit 10.7)
10.38	*	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective as of 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)
10.39	*	PG&E Corporation 2010 Executive Stock Ownership Guidelines, as amended effective as of December 10, 2025
10.40	*	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)
10.41	*	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated as of 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)
10.42	*	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as amended 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)
10.43	*	Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated as of 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)
10.44	*	Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated as of 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)
10.45	*	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of 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)
10.46	*	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated as of 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)
10.47	*	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated as of 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)
10.48	*	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 10.08)
10.49	*	Form of Director and Officer Indemnification Agreement, as amended effective as of February 20, 2025 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2025 (File No. 1-12609), Exhibit 10.3)
19		Insider Trading Standard
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 Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2		Certifications of the Principal Executive Officer and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1	**	Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2	**	Certifications of the Principal Executive Officer and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
97.1		PG&E Corporation and Pacific Gas and Electric Company Dodd-Frank Clawback Policy (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2023 (File No. 1-12609), Exhibit 97.1)
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)

*	Management contract or compensatory agreement
**	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, 2025 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 (Registrant)		PACIFIC GAS AND ELECTRIC COMPANY (Registrant)
	/s/ PATRICIA K. POPPE		/s/ SUMEET SINGH
	Patricia K. Poppe		Sumeet Singh
By:	Chief Executive Officer	By:	Chief Executive Officer, Pacific Gas and Electric Company, and Executive Vice President, Energy Delivery
Date:	February 11, 2026	Date:	February 11, 2026

Signature	Title	Date
A. Principal Executive Officers		
/s/ PATRICIA K. POPPE Patricia K. Poppe	Chief Executive Officer (PG&E Corporation)	February 11, 2026
/s/ SUMEET SINGH Sumeet Singh	Chief Executive Officer, Pacific Gas and Electric Company, and Executive Vice President, Energy Delivery (Pacific Gas and Electric Company)	February 11, 2026
B. Principal Financial Officers		
/s/ CAROLYN J. BURKE Carolyn J. Burke	Executive Vice President and Chief Financial Officer (PG&E Corporation)	February 11, 2026
/s/ STEPHANIE N. WILLIAMS Stephanie N. Williams	Vice President and Controller (PG&E Corporation) Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2026
C. Principal Accounting Officer		
/s/ STEPHANIE N. WILLIAMS Stephanie N. Williams	Vice President and Controller (PG&E Corporation) Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2026

D. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)

* /s/ RAJAT BAHRI	Director	February 11, 2026
Rajat Bahri		
* /s/ CHERYL F. CAMPBELL	Director	February 11, 2026
Cheryl F. Campbell	Chair of the Board (Pacific Gas and Electric Company)	
* /s/ EDWARD G. CANNIZZARO	Director	February 11, 2026
Edward G. Cannizzaro		
* /s/ KERRY W. COOPER	Director	February 11, 2026
Kerry W. Cooper	Chair of the Board (PG&E Corporation)	
* /s/ LEO P. DENAULT	Director	February 11, 2026
Leo P. Denault		
* /s/ JESSICA L. DENECOUR	Director	February 11, 2026
Jessica L. Denecour		
* /s/ MARK E. FERGUSON III	Director	February 11, 2026
Mark E. Ferguson III		
* /s/ W. CRAIG FUGATE	Director	February 11, 2026
W. Craig Fugate		
* /s/ ARNO L. HARRIS	Director	February 11, 2026
Arno L. Harris		
* /s/ CARLOS M. HERNANDEZ	Director	February 11, 2026
Carlos M. Hernandez		
* /s/ JOHN O. LARSEN	Director	February 11, 2026
John O. Larsen		
* /s/ PATRICIA K. POPPE	Director	February 11, 2026
Patricia K. Poppe		
* /s/ WILLIAM L. SMITH	Director	February 11, 2026
William L. Smith		

* /s/ BENJAMIN F. WILSON Benjamin F. Wilson	Director	February 11, 2026
* /s/ SUMEET SINGH Sumeet Singh	Director (Pacific Gas and Electric Company)	February 11, 2026
*By: /s/ JOHN R. SIMON John R. Simon, Attorney-in-Fact		February 11, 2026

PG&E CORPORATION
SCHEDULE I — CONSOLIDATED FINANCIAL INFORMATION OF PG&E CORPORATION ("PARENT")
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Years Ended December 31,		
(in millions, except per share amounts)	**2025**	**2024**	**2023**
Administrative service revenue	$ 194	$ 146	$ 154
Operating expenses	(207)	(167)	(165)
Interest income	11	15	13
Interest expense	(315)	(270)	(365)
Other expense	(145)	(17)	(21)
Equity in earnings of subsidiaries	3,065	2,697	2,530
Income Before Income Taxes	**2,603**	**2,404**	**2,146**
Income tax benefit	(86)	(94)	(96)
Net Income	**$ 2,689**	**$ 2,498**	**$ 2,242**
Preferred stock dividend requirement	96	23	—
Income Available for Common Shareholders	**$ 2,593**	**$ 2,475**	**$ 2,242**
Other Comprehensive Income (Loss)			
Pension and other postretirement benefit plans obligations (net of taxes of $0, $3, and $6, at respective dates)	(3)	(7)	(16)
Net unrealized gain on available-for-sale securities (net of taxes of $0, $0, and $0, respectively)	—	1	—
Total other comprehensive income (loss)	(3)	(6)	(16)
Comprehensive Income	**$ 2,590**	**$ 2,469**	**$ 2,226**
Weighted Average Common Shares Outstanding, Basic	**2,197**	**2,141**	**2,064**
Weighted Average Common Shares Outstanding, Diluted	**2,202**	**2,147**	**2,138**
Net Earnings Per Common Share, Basic	**$ 1.18**	**$ 1.16**	**$ 1.09**
Net Earnings Per Common Share, Diluted	**$ 1.18**	**$ 1.15**	**$ 1.05**

PG&E CORPORATION
SCHEDULE I — CONSOLIDATED FINANCIAL INFORMATION OF PG&E CORPORATION (“PARENT”) – (Continued)
CONSOLIDATED BALANCE SHEETS

	Balance at December 31,	
(in millions)	**2025**	**2024**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 360	$ 235
Restricted cash and restricted cash equivalents	1	1
Advances to affiliates	54	13
Income taxes receivable	39	2
Total current assets	**454**	**251**
Other Noncurrent Assets		
Investments in subsidiaries	45,110	42,829
Other investments	182	175
Deferred income taxes	682	633
Total other noncurrent assets	**45,974**	**43,637**
TOTAL ASSETS	**$ 46,428**	**$ 43,888**
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable – other	146	36
Income taxes payable	—	1
Other current liabilities	444	420
Total current liabilities	**590**	**457**
Noncurrent Liabilities		
Long-term debt	5,622	5,612
Other noncurrent liabilities	151	141
Total noncurrent liabilities	**5,773**	**5,753**
Shareholders’ Equity		
Mandatory convertible preferred stock	1,579	1,579
Common stock	39,168	39,086
Reinvested earnings	(650)	(2,966)
Accumulated other comprehensive loss	(32)	(21)
Total shareholders’ equity	**40,065**	**37,678**
TOTAL LIABILITIES AND EQUITY	**$ 46,428**	**$ 43,888**

PG&E CORPORATION
SCHEDULE I – CONSOLIDATED FINANCIAL INFORMATION OF PG&E CORPORATION (“PARENT”) – (Continued)
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year ended December 31,		
	2025	2024	2023
Cash Flows from Operating Activities:			
Net income	$ 2,689	$ 2,498	$ 2,242
Adjustments to reconcile net income to net cash provided by operating activities:			
Stock-based compensation amortization	82	53	4
Equity in earnings of subsidiaries	(3,065)	(2,699)	(2,530)
Deferred income taxes and tax credits, net	(49)	(94)	(116)
Current income taxes payable	(33)	—	9
Other	55	9	40
Net cash used in operating activities	**(321)**	**(233)**	**(351)**
Cash Flows From Investing Activities:			
Investment in subsidiaries	(1,575)	(5,360)	(1,290)
Dividends received from subsidiaries [1]	2,350	2,025	1,775
Net cash provided by (used in) investing activities	**775**	**(3,335)**	**485**
Cash Flows From Financing Activities:			
Repayments under term loan credit facilities	—	(500)	(2,181)
Proceeds from issuance of convertible notes, net of discount and issuance costs of $0, $0, and $27 at respective dates	—	—	2,123
Proceeds from issuance of long-term debt, net of premium and issuance costs of $0, $4, and $0 at respective dates	—	1,496	—
Common stock issued	—	1,128	—
Mandatory convertible preferred stock issued	—	1,579	—
Mandatory convertible preferred stock dividends paid	(97)	—	—
Common stock dividend paid	(220)	(86)	—
Other	(12)	(8)	(6)
Net cash provided by (used in) financing activities	**(329)**	**3,609**	**(64)**
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**125**	**41**	**70**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at January 1	**236**	**195**	**125**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at December 31	**$ 361**	**$ 236**	**$ 195**
Less: Restricted cash and restricted cash equivalents	(1)	(1)	(3)
Cash and cash equivalents at December 31	**$ 360**	**$ 235**	**$ 192**
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest, net of amounts capitalized	$ (306)	$ (215)	$ (309)
Supplemental disclosures of noncash investing and financing activities			
Changes to PG&E Corporation common stock and treasury stock in connection with the share exchange with the Fire Victim Trust	$ —	$ —	$ (2,517)
Common stock dividends declared but not yet paid	111	55	21
Mandatory convertible preferred stock dividends declared but not yet paid	23	23	—

[1] Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries as an investing cash flow.

PG&E CORPORATION

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2025, 2024, and 2023

(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:					
2025:					
Allowance for uncollectible accounts [1]	$ 418	$ 362	$ —	$ 372	$ 408
2024:					
Allowance for uncollectible accounts [1]	$ 445	$ 312	$ —	$ 339	$ 418
2023:					
Allowance for uncollectible accounts [1]	$ 166	$ 624	$ —	$ 345	$ 445

(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, 2025, 2024, and 2023

(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:					
2025:					
Allowance for uncollectible accounts [1]	$ 418	$ 362	$ —	$ 372	$ 408
2024:					
Allowance for uncollectible accounts [1]	$ 445	$ 312	$ —	$ 339	$ 418
2023:					
Allowance for uncollectible accounts [1]	$ 166	$ 624	$ —	$ 345	$ 445

(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.