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

FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2025

OR

☐ 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	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
300 Lakeside Drive	300 Lakeside Drive
Oakland, California 94612	Oakland, California 94612

Address of principal executive offices, including zip code

PG&E Corporation	Pacific Gas and Electric Company
415 973-1000	415 973-7000

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% redeemable	PCG-PI	NYSE American LLC
6.000% Series A Mandatory Convertible Preferred Stock, no par value	PCG-PrX	The New York Stock Exchange

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, 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:	☒ Large accelerated filer	☐ Accelerated filer
	☐ Non-accelerated filer	
	☐ Smaller reporting company	☐ Emerging growth company
Pacific Gas and Electric Company:	☐ Large accelerated filer	☐ Accelerated filer
	☒ Non-accelerated filer	
	☐ Smaller reporting 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 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 Sections 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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common stock outstanding as of October 15, 2025:

PG&E Corporation:	2,675,654,015*
Pacific Gas and Electric Company:	264,374,809

*Includes 477,743,590 shares of common stock held by Pacific Gas and Electric Company.

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2025
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UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt-Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 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
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
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
CPUC	California Public Utilities Commission
CRR	congestion revenue rights
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
EMANI	European Mutual Association for Nuclear Insurance
Emergence Date	July 1, 2020, the effective date of the Plan in the Chapter 11 Cases
EPS	earnings per common share
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
Form 10-Q	PG&E Corporation's and the Utility's joint Quarterly Report on Form 10-Q
FRMMA	Fire Risk Mitigation Memorandum Account
GAAP	United States Generally Accepted Accounting Principles
GHG	greenhouse gas
GRC	general rate case
HSMA	Hazardous Substance Memorandum Account
IOUs	investor-owned utility(ies)
IRC	Internal Revenue Code of 1986, as amended
Lakeside Building	300 Lakeside Drive, Oakland, California, 94612
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part I, Item 2, of this Form 10-Q
MGP	manufactured gas plants
NAV	net asset value
NEIL	Nuclear Electric Insurance Limited, a mutual insurer owned by utilities with nuclear facilities
OEIS	Office of Energy Infrastructure Safety (successor to the Wildfire Safety Division of the CPUC)
PD	proposed decision

PERA	Public Employees Retirement Association of New Mexico
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
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
RUBA	Residential Uncollectibles Balancing Account
SB	Senate Bill
SEC	United States Securities and Exchange Commission
SFGO	The Utility’s former 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
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 losses, including penalties and fines associated with various investigations and proceedings; forecasts of capital expenditures; forecasts of cost savings; estimates and assumptions used in critical accounting estimates, including those relating to insurance receivables, regulatory assets and liabilities, environmental remediation, litigation, third-party claims, the Wildfire Fund, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "commit," "goal," "target," "will," "may," "should," "would," "could," "potential," and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the extent to which the Wildfire Fund, 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; 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; and the effect on PG&E Corporation's and the Utility's reputations of such wildfires, investigations, and proceedings;

- the extent to which the Utility's wildfire mitigation initiatives are effective, including the Utility's ability to comply with the targets and metrics set forth in its WMP; the effectiveness of its system hardening, including undergrounding; the cost of the program and the timing and outcome of any proceeding to recover such costs through rates; and any determination by the OEIS that the Utility has not complied with its WMP;

- 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 driven by 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, driven by customer self-generation, customer departures to community choice aggregators, direct access providers, and government-owned utilities, and legislative mandates to reduce the use of natural gas; 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 and other sectors of the economy, and the resulting changes in customer demand for its natural gas and electric services;

- cyber or physical attacks, including cybersecurity breaches, 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 Utility's ability to attract or retain specialty personnel;

- 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, 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 outcome of 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 applicable to its gas and electric operations; the construction, expansion, or replacement of its electric and gas facilities; electric grid reliability; audit, inspection and maintenance practices; customer billing and privacy; physical and cybersecurity protections; environmental laws and regulations; or otherwise, such as fines; penalties; remediation obligations; or the implementation of corporate governance, operational or other changes in connection with the Enhanced Oversight and Enforcement Process;

- 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;

- 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 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 10 of the Notes to the Condensed 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;

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

- 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 costs through rates, including its renewable energy procurement costs;

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

- the risks and uncertainties associated with high rates for the Utility’s customers;

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

- the severity, extent, and duration of pandemics and the Utility’s ability to collect on customer receivables; 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” in the 2024 Form 10-K and a detailed discussion of these matters contained in Item 7: “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the 2024 Form 10-K and Part I, Item 2 in this Form 10-Q. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and proxy statements are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com, as promptly as practicable after they are filed with, or furnished to, the SEC. 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. Specifically, within two hours during business hours or four hours outside of business hours of the determination that an incident is attributable or allegedly attributable to the Utility's electric facilities and has resulted in property damage estimated to exceed $200,000, a fatality or injury requiring medical attention from a healthcare professional at a hospital or other medical facility, or media coverage from a major news outlet, or a government entity investigating whether the infrastructure owned or operated by the utility caused a wildfire, the Utility is required to submit an electric incident report including information about such incident to the CPUC. The information included in an electric incident report is limited and may not include important information about the facts and circumstances about the incident due to the limited scope of the reporting requirements and timing of the report and is necessarily limited to information to which the Utility has access at the time of the report. Ignitions are also reportable under CPUC Decision 14-02-015 when they involve self-propagating fire of material other than electrical or communication facilities; the fire traveled greater than one linear meter from the ignition point; and the Utility has knowledge that the fire occurred. It is possible that any of these filings or information included therein could be deemed to be material information. The information contained on such websites 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 such websites solely for the information of investors and do not intend the addresses to be active links.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, see Item 1A: "Risk Factors" in the 2024 Form 10-K, as supplemented in the section of this Form 10-Q entitled "Forward-Looking Statements."

PART I. FINANCIAL INFORMATION

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

This is a combined Form 10-Q of PG&E Corporation and the Utility and includes separate Condensed Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in Part I, Item 1. It should also be read in conjunction with the 2024 Form 10-K.

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 Part I, Item 1: "Business" in the 2024 Form 10-K 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, and transportation of natural gas; weather conditions; criminal, civil and regulatory penalties or charges for wildfires; the outcomes of ratemaking proceedings; and changes in interest expense as a result of additional debt issuances or changes in interest rates.

The discussions related to the results of operations and liquidity for the three and nine months ended September 30, 2024 compared to the same periods in 2023 are incorporated by reference to Part I, Item 2: "Management's Discussion and Analysis of Financial Condition and Results of Operations" in PG&E Corporation's and the Utility's combined Form 10-Q for the three months ended September 30, 2024, which was filed with the SEC in November 2024.

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 Enhanced Powerline Safety Settings ("EPSS"), PSPS, vegetation management, asset inspections, and system hardening (such as undergrounding). The Utility's wildfire mitigation efforts have also benefited in recent years from improved ignition response and situational awareness tools like weather stations and risk modeling. These initiatives reduce the Utility's wildfire risk. The success of the Utility's wildfire mitigation efforts depends on many factors, including whether the Utility can retain or contract for the workforce necessary to execute its wildfire mitigation actions.

  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 Condensed Consolidated Financial Statements in Part I, Item 1. The extent to which the Utility will be able to recover these expenditures and other potential costs through rates is uncertain. If additional requirements are imposed that go beyond current expectations, such requirements could have a substantial impact on the costs of the Utility's wildfire mitigation initiatives.

  The Utility is subject to a number of legal and regulatory requirements related to its wildfire mitigation efforts, which require periodic inspections of electric assets and ongoing reporting related to this work. Although the Utility believes that it has complied substantially with these requirements, it regularly reviews and has identified instances of noncompliance. The Utility intends to update the CPUC and the OEIS based on its ongoing review. The Utility could face fines, penalties, enforcement action, or other adverse legal or regulatory consequences for noncompliance related to wildfire mitigation efforts.

Despite these extensive measures, 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 change (in particular, extended periods of seasonal dryness coupled with periods of high wind velocities and other storms), infrastructure, and vegetation conditions. Once an ignition has occurred, the Utility may be unable to control the extent of damages, which is primarily determined by environmental conditions (including weather and vegetation conditions), third-party suppression efforts, and the location of the wildfire.

The financial impact of past wildfires is significant. As of September 30, 2025, PG&E Corporation and the Utility had recorded aggregate liabilities of $1.325 billion, $2.125 billion, and $250 million for claims in connection with the 2019 Kincade fire, the 2021 Dixie fire, and the 2022 Mosquito fire, respectively, and in each case before available insurance, and, in the case of the 2021 Dixie fire and the 2022 Mosquito fire, other probable cost recoveries. These liability amounts correspond to the lower end of the range of reasonably estimable probable losses with the exception of amounts relating to the 2019 Kincade fire, which represent the best estimate of the liability, but 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. See "Loss Recoveries" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

As of September 30, 2025, the Utility has recorded insurance receivables of $523 million for the 2021 Dixie fire and $256 million for the 2022 Mosquito fire.

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 impacts of AB 1054 and SB 254 on PG&E Corporation and the Utility are subject to numerous, substantial uncertainties, including the Utility's ability to demonstrate to the CPUC that paid wildfire-related costs were just and reasonable and therefore not subject to reimbursement by the Utility. The Utility's ability to recover wildfire costs also 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.

With respect to the Wildfire Fund, Edison International and Southern California Edison Company (together, "SCE") have 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 Condensed Consolidated Financial Statements in Part I, Item 1). 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 $1.125 billion for the 2021 Dixie fire, of which it had received $609 million as of September 30, 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 all or a portion of expenses that it has recorded as receivables. As of September 30, 2025, the Utility has recorded receivables for regulatory recovery of $626 million for the 2021 Dixie fire and $61 million for the 2022 Mosquito fire. See "2021 Dixie Fire" and "2022 Mosquito Fire" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 for more information.

- *The Timing and Outcome of Ratemaking and Other Proceedings.* 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). The CPUC also 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. Although the Utility generally seeks to recover its recorded costs on a timely basis, in recent years, the amount of the costs recorded in memorandum and balancing accounts has increased. 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 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1, and "Regulatory Matters" below.

- *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 depends on capital market conditions. Increased volatility in capital markets and 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" in the 2024 Form 10-K and "Forward-Looking Statements" above.

Tax Matters

PG&E Corporation had a U.S. federal net operating loss carryforward of approximately $33.7 billion and a California net operating loss carryforward of approximately $34.9 billion as of December 31, 2024.

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. 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 for PG&E Corporation, as amended by the 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 2,675,654,015 common shares outstanding as of October 15, 2025, only 2,197,910,425 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 October 15, 2025, a person's effective Percentage Stock Ownership limitation for purposes of the Amended Articles as of October 15, 2025 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 the three and nine months ended September 30, 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 for the three and nine months ended September 30, 2025 and 2024:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2025**	**2024**	**2025**	**2024**
Consolidated Total	$ 823	$ 576	$ 1,951	$ 1,828
PG&E Corporation	(87)	(39)	(259)	(126)
Utility	$ 910	$ 615	$ 2,210	$ 1,954

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

Utility

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2025**	**2024**	**2025**	**2024**
Operating Revenues				
Electric	$ 4,755	$ 4,538	$ 13,304	$ 13,048
Natural gas	1,495	1,403	4,827	4,740
Total operating revenues	**6,250**	**5,941**	**18,131**	**17,788**
Operating Expenses				
Cost of electricity	1,015	835	2,013	1,919
Cost of natural gas	131	89	738	822
Operating and maintenance	2,636	2,678	8,128	8,062
SB 901 securitization charges, net	35	33	35	33
Wildfire-related claims, net of recoveries	1	74	100	70
Wildfire Fund expense	86	139	271	295
Depreciation, amortization, and decommissioning	1,132	1,059	3,302	3,134
Total operating expenses	**5,036**	**4,907**	**14,587**	**14,335**
Operating Income	**1,214**	**1,034**	**3,544**	**3,453**
Interest income	91	153	384	486
Interest expense	(691)	(721)	(2,059)	(2,125)
Other income, net	97	82	251	240
Income Before Income Taxes	**711**	**548**	**2,120**	**2,054**
Income tax (benefit) expense	(202)	(70)	(100)	90
Net Income	**913**	**618**	**2,220**	**1,964**
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	**$ 910**	**$ 615**	**$ 2,210**	**$ 1,954**

Operating Revenues

The Utility's electric and natural gas operating revenues increased by $309 million, or 5%, in the three months ended September 30, 2025, compared to the same period in 2024. This increase was primarily due to:

- approximately $150 million in revenues to recover costs associated with extended operations at DCPP in the three months ended September 30, 2025, with no comparable revenues in the same period in 2024;
- approximately $140 million in interim rate relief authorized in the 2023 WMCE proceeding (see "2023 Wildfire Mitigation and Catastrophic Events Application" below) in the three months ended September 30, 2025, with no comparable revenues in the same period in 2024;
- an increase in revenues to recover the cost of electricity procurement (which increased by approximately $180 million) in the three months ended September 30, 2025, as compared to costs in the same period in 2024. These costs are passed through to customers and do not impact net income; and
- an increase in revenues to recover the cost of natural gas (which increased by approximately $42 million) in the three months ended September 30, 2025, as compared to costs in the same period in 2024. These costs are passed through to customers and do not impact net income.

Partially offset by:

- approximately $100 million in lower interim rate relief as authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below) in the three months ended September 30, 2025, compared with the same period in 2024; and

- an approximately $60 million decrease in revenue due to expense disallowances as per the 2022 WMCE final decision (see "2022 WMCE Application" below) in the three months ended September 30, 2025 with no comparable decrease in the same period in 2024.

The Utility's electric and natural gas operating revenues increased by $343 million, or 2%, in the nine months ended September 30, 2025, compared to the same period in 2024. This increase was primarily due to:

- approximately $520 million in revenues to recover costs associated with extended operations at DCPP in the nine months ended September 30, 2025, with no comparable revenues in the same period in 2024;

- approximately $490 million in interim rate relief authorized in the 2023 WMCE proceeding (see "2023 Wildfire Mitigation and Catastrophic Events Application" below) in the nine months ended September 30, 2025, with no comparable revenues in the same period in 2024;

- an increase in revenues to recover the cost of electricity procurement (which increased by approximately $94 million) in the nine months ended September 30, 2025, compared to costs in the same period in 2024. These costs are passed through to customers and do not impact net income; and

- approximately $50 million in revenues authorized in the GOSMA petition for modification final decision in the nine months ended September 30, 2025, with no comparable revenues in the same period in 2024.

Partially offset by:

- approximately $540 million in interim rate relief authorized in the 2022 WMCE proceeding (see "2022 WMCE Application" below) in the nine months ended September 30, 2024, with no comparable revenues in the same period in 2025;

- approximately $130 million in lower interim rate relief as authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below) in the nine months ended September 30, 2025, compared with the same period in 2024;

- a decrease in revenues to recover the cost of natural gas (which decreased by approximately $84 million) in the nine months ended September 30, 2025, compared to costs in the same period in 2024. These costs are passed through to customers and do not impact net income;

- approximately $60 million in lower revenues related to winter storm response in the nine months ended September 30, 2025, compared to the same period in 2024; and

- an approximately $60 million decrease in revenue due to expense disallowances as per the 2022 WMCE final decision (see "2022 WMCE Application" below) in the nine months ended September 30, 2025, with no comparable decrease in the same period in 2024.

Cost of Electricity

The Utility's Cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), fuel and associated transmission costs used in its own generation facilities, fuel and associated transmission costs supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. See Note 8 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1. Cost of electricity also includes net energy sales (Utility owned and third parties' generation) in the CAISO electricity markets and directly from third parties.

The Cost of electricity increased by $180 million, or 22%, in the three months ended September 30, 2025, compared to the same period in 2024. This increase was primarily the result of higher procurement costs and lower renewable energy credit sales in the three months ended September 30, 2025, compared with the same period in 2024.

The Cost of electricity increased by $94 million, or 5%, in the nine months ended September 30, 2025, compared to the same period in 2024. This increase was primarily the result of higher procurement costs and higher nuclear fuel amortization, partially offset by increased renewable energy credit sales in the nine months ended September 30, 2025, compared to the same period in 2024.

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 8 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

The Cost of natural gas increased by $42 million, or 47%, in the three months ended September 30, 2025, compared to the same period in 2024. This increase was primarily the result of an increase in GHG emissions expenses, increases in natural gas prices and volumes, and increases in gas storage contract expenses, compared to the same period in 2024.

The Cost of natural gas decreased by $84 million, or 10%, in the nine months ended September 30, 2025, compared to the same period in 2024. This decrease was primarily the result of a reduction in GHG emissions expenses and favorable price risk management results, partially offset by increases in natural gas prices and volumes, compared to the same period in 2024.

Operating and Maintenance

The Utility's Operating and maintenance expenses decreased by $42 million, or 2%, in the three months ended September 30, 2025, compared to the same period in 2024. This decrease was primarily due to:

- approximately $210 million in costs related to a FERC order denying the capitalization of certain vegetation management costs and ordering the Utility to record these as operating expenses, resulting in an increase in operating expense in the three months ended September 30, 2024, with no comparable costs in the same period in 2025;

- approximately $100 million in lower interim rate relief as authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below) in the three months ended September 30, 2025, compared with the same period in 2024; and

- an approximately $30 million reduction in insurance costs related to the Utility's adoption of non-wildfire-related self-insurance in the three months ended September 30, 2025, compared with the same period in 2024.

Partially offset by:

- approximately $130 million in costs associated with extended operations at DCPP in the three months ended September 30, 2025, with no comparable costs in the same period in 2024;

- approximately $140 million in previously deferred expenses authorized in the 2023 WMCE application (see "2023 WMCE Application" below) in the three months ended September 30, 2025, with no comparable costs in the same period in 2024;

- approximately $40 million increase due to recognition of previously deferred expenses authorized as per the 2022 WMCE final decision (see "2022 WMCE Application" below) in the three months ended September 30, 2025, with no comparable costs in the same period in 2024; and

- an approximately $40 million increase in electric transmission expenses in the three months ended September 30, 2025, compared to the same period in 2024.

The Utility's Operating and maintenance expenses increased by $66 million, or 1%, in the nine months ended September 30, 2025, compared to the same period in 2024. This increase was primarily due to:

- approximately $490 million in previously deferred expenses authorized in the 2023 WMCE application (see "2023 WMCE Application" below) in the nine months ended September 30, 2025, with no comparable costs in the same period in 2024;
- approximately $470 million in costs associated with extended operations at DCPP in the nine months ended September 30, 2025, with no comparable costs in the same period in 2024;
- approximately $80 million increase in electric transmission expenses in the nine months ended September 30, 2025, compared to the same period in 2024; and
- approximately $40 million increase due to recognition of previously deferred expenses as per the 2022 WMCE final decision (see "2022 WMCE Application" below) in the nine months ended September 30, 2025, with no comparable costs in the same period in 2024.

Partially offset by:

- 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 the nine months ended September 30, 2024, with no comparable costs in the same period in 2025;
- approximately $210 million in costs related to a FERC order denying the capitalization of certain vegetation management costs and ordering the Utility to record these as operating expense, resulting in an increase in operating expense in the nine months ended September 30, 2024, with no comparable costs in the same period in 2025;
- approximately $130 million in lower interim rate relief as authorized in the WGSC proceeding (see "Wildfire and Gas Safety Costs Recovery Application" below) in the nine months ended September 30, 2025, compared with the same period in 2024;
- approximately $60 million in lower costs related to winter storm response in the nine months ended September 30, 2025, compared to the same period in 2024; and
- approximately $40 million reduction in insurance costs related to the Utility's adoption of non-wildfire-related self-insurance in the nine months ended September 30, 2025, compared with the same period in 2024.

Wildfire-Related Claims, Net of Recoveries

The Utility's Wildfire-related claims, net of recoveries decreased by $73 million, or 99%, in the three months ended September 30, 2025, compared to the same period in 2024. The Utility recognized pre-tax charges of $75 million related to the 2019 Kincade fire in the three months ended September 30, 2024, with no comparable costs in the same period in 2025.

The Utility's Wildfire-related claims, net of recoveries increased by $30 million, or 43%, in the nine months ended September 30, 2025, compared to the same period in 2024. The Utility recognized pre-tax charges of $100 million related to the 2019 Kincade fire in the nine months ended September 30, 2025, as compared to pre-tax charges of $75 million related to the 2019 Kincade fire in the same period in 2024.

Wildfire Fund Expense

The Utility's Wildfire Fund expense decreased by $53 million, or 38%, and $24 million, or 8%, in the three and nine months ended September 30, 2025, compared to the same periods in 2024. These decreases were due to lower accelerated amortization associated with the Wildfire Fund receivable for the 2021 Dixie fire in the three and nine months ended September 30, 2025, compared to the same periods in 2024.

Depreciation, Amortization, and Decommissioning

The Utility's Depreciation, amortization and decommissioning expenses increased by $73 million, or 7%, and $168 million, or 5%, in the three and nine months ended September 30, 2025, compared to the same periods in 2024. These increases were primarily due to the growth in plant balance from capital additions, partially offset by an increase in deferred depreciation expense for costs pending regulatory approval.

Interest Income

The Utility’s Interest income decreased by $62 million, or 41%, and $102 million, or 21%, in the three and nine months ended September 30, 2025, compared to the same periods in 2024. These decreases were primarily due to a decrease in interest rates and interest-bearing account balances in the three and nine months ended September 30, 2025 compared to the same periods in 2024.

Interest Expense

The Utility’s Interest expense decreased by $30 million, or 4%, and $66 million, or 3%, in the three and nine months ended September 30, 2025, compared to the same periods in 2024. These decreases were primarily due to a decrease in short-term debt with higher, variable interest rates, partially offset by an increase in long-term debt.

Other Income, Net

There was no material change to Other income, net for the periods presented.

Income Tax Provision

The Utility’s Income tax provision decreased by $132 million, or 189%, and $190 million, or 211%, in the three and nine months ended September 30, 2025, compared to the same periods in 2024, primarily due to an increased tax repairs deduction and an additional deduction for certain costs attributable to electric generation.

The effective tax rates were (28.3)% and (4.7)%, and (12.8)% and 4.4%, for the three and nine months ended September 30, 2025 and 2024, respectively. The change in effective tax rate is primarily due to an estimated tax benefit related to an increase in repairs deduction and an additional deduction for certain costs attributable to electric generation. The Utility’s effective tax rate is below the federal statutory rate of 21% for 2025 and 2024 primarily due to the effect of the increase in 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. These amounts also reflect the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Cuts and Jobs Act of 2017.

Import Tariffs

Changes to import tariffs have not had and are not expected to have a material impact on either PG&E Corporation’s or the Utility’s results of operations. PG&E Corporation and the Utility will continue monitoring and assessing the impacts of changes to import tariffs and will continue working to mitigate related cost increases.

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.

PG&E Corporation and the Utility have various contractual commitments which impact cash requirements. These commitments are discussed in "Purchase Commitments" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

As of September 30, 2025, PG&E Corporation and the Utility had access to approximately $6.1 billion of total liquidity comprised of $253 million of the Utility's Cash and cash equivalents, $151 million of PG&E Corporation's Cash and cash equivalents, and $5.7 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.

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 September 30, 2025, PG&E Corporation and the Utility had cash and cash equivalents of $151 million and $253 million, respectively.

Self-Insurance

As of September 30, 2025, the Utility had contributed $988 million to Pacific Energy Risk Solutions, LLC, its wholly-owned subsidiary and captive insurance company for the administration of wildfire liability self-insurance. As of September 30, 2025, $8 million was classified as Restricted cash and restricted cash equivalents due to minimum capital and surplus requirements, $8 million was classified as Cash and cash equivalents, and $1.0 billion, measured at fair value, was classified as Wildfire self-insurance asset.

As of September 30, 2025, the Utility had contributed $96 million to Pacific Casualty Insurance Company, LLC, its wholly-owned subsidiary and captive insurance company for the administration of non-wildfire liability self-insurance. As of September 30, 2025, $19 million was classified as Restricted cash and cash equivalents due to minimum capital and surplus requirements, an immaterial amount was classified as cash and cash equivalents, and $77 million, measured at fair value, was included in Other current assets.

For more information, see "Self-Insurance" in Note 10 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

Financial Resources

Equity Financings

PG&E Corporation has completed the planned equity financing for its $73 billion capital expenditure plan for 2026 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 10 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

Debt Financings

Utility

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

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 expects to use the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount 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 expects to use the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount 3.15% First Mortgage Bonds due January 1, 2026. The Utility expects to use the remaining net proceeds from the offerings for general corporate purposes.

Credit Facilities and Term Loans

Utility

As of September 30, 2025, PG&E Corporation and the Utility had $650 million and $5.1 billion available under their respective $650 million and $5.4 billion revolving credit facilities. The Utility also has access to the Receivables Securitization Program, under which the Utility may borrow 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.

On April 11, 2025, the Utility amended its existing $525 million term loan agreement to extend the maturity 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 up of 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.

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.

For more information, see "Credit Facilities and Term Loans" in Note 4 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

Other Financings

DOE Loan Guarantee Agreement

On January 17, 2025, the Utility entered into the following agreements: (1) the DOE Loan Guarantee Agreement; (2) a note purchase agreement dated as of January 17, 2025 (the "Note Purchase Agreement"), among the Utility, the Federal Financing Bank ("FFB"), and the DOE; and (3) a future advance promissory note dated January 17, 2025, made by the Utility to FFB (the "Note" and together with the Note Purchase Agreement, the "FFB Note Documents").

The FFB Note Documents provide for a multi-advance term loan facility (the "Facility"), under which the Utility may make quarterly term loan borrowings through FFB, subject to satisfaction of certain conditions. Proceeds of the advances under the Facility are to be used by the Utility to reimburse for "Eligible Project Costs" previously incurred and either expended or accrued by the Utility in connection with projects that the DOE has determined to be "Eligible Projects" (each as defined in the DOE Loan Guarantee Agreement). The aggregate amount of advances under the Facility may not exceed $15 billion.

As of the date of this report, the Utility has not borrowed any advances under the Facility. The Utility is not able to predict the timing or amount of any funds it may receive from the Facility in the future as a result of the recent change in the administration.

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.

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

Utility

On each of November 29, 2024, February 20, and May 22, 2025, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock totaling $3.5 million, which were paid on February 18, May 15, and August 15, 2025, to holders of record as of January 31, April 30 and July 31, 2025, respectively. On September 18, 2025, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock totaling $3.5 million, payable on November 15, 2025, to holders of record as of October 31, 2025.

On each of February 20, May 22, and September 18, 2025, the Board of Directors of the Utility declared common stock dividends of $575 million, which were paid to PG&E Corporation on March 18, May 30, and September 26, 2025, respectively.

PG&E Corporation

On each of November 29, 2024, February 20, May 22, and September 18, 2025, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.025 per share, each declaration totaling $55 million, which were paid on January 15, April 15, July 15, and October 15, 2025, to holders of record as of December 31, 2024, March 31, June 30, and September 30, 2025, respectively.

On December 12, 2024, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.7167 per mandatory convertible preferred share, totaling $23 million, which was paid on February 27, 2025, to holders of record as of February 14, 2025. On each of February 20 and May 22, 2025, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.75 per mandatory convertible preferred share, each declaration totaling $24 million, which were paid on May 29 and August 28, 2025, to holders of record as of May 15 and August 15, 2025, respectively. On September 18, 2025, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.75 per mandatory convertible preferred share, totaling $24 million, payable on December 1, 2025, to holders of record as of November 14, 2025.

Utility Cash Flows

PG&E Corporation's condensed consolidated cash flows consist primarily of cash flows related to the Utility. The following discussion presents the Utility's cash flows for the nine months ended September 30, 2025 and 2024.

The Utility's cash flows were as follows:

	Nine Months Ended September 30,	
(in millions)	**2025**	**2024**
Net cash provided by operating activities	$ 7,019	$ 6,272
Net cash used in investing activities	(9,250)	(8,219)
Net cash provided by financing activities	1,874	2,257
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**$ (357)**	**$ 310**

Operating Activities

Net cash provided by operating activities increased by $0.7 billion, or 12%, during the nine months ended September 30, 2025 as compared to the same period in 2024. This increase was primarily due to:

- an increase in collections driven in part by recoveries related to DCPP extended operations and 2023 WMCE interim rate relief;
- a decrease in non-wildfire related insurance costs;
- a decrease in cost of energy as a result of lower carbon allowance purchases; and
- a decrease in wildfire-related payments, net of recoveries.

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of cash operating expenses. The Utility's receipts from customers are expected to increase primarily as a result of increases in the Utility's rate base and from cost recovery applications (see "Cost Recovery Proceedings" below for more information).

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 10 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1);

- 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 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

Investing Activities

The following table summarizes changes in key components of the Utility's investing cash flows for the nine months ended September 30, 2025, compared to September 30, 2024.

(in millions)	Nine Months Ended September 30,
Cash used in investing activities - 2024	**$ (8,219)**
Capital expenditures	(1,090)
Net purchases related to customer credit trust investments	(233)
Net purchases related to self-insurance investment and other investing activities	292
Net increase in cash used in investing activities	**(1,031)**
Cash used in investing activities - 2025	**$ (9,250)**

Net cash used in investing activities increased by $1.0 billion, or 13%, during the nine months ended September 30, 2025 as compared to the same period in 2024. This increase was primarily due to a $349 million payment for the purchase of the Oakland headquarters, as discussed in Note 2 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1, an increase in investments in undergrounding, and additional distribution poles for the WMP.

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 funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities. Pursuant to SB 901, the funds in the customer credit trust, along with accumulated earnings, are used exclusively to fund a monthly credit to customers.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur $13.2 billion of capital expenditures in 2025.

Financing Activities

The following table summarizes changes in key components of the Utility's financing cash flows for the nine months ended September 30, 2025, compared to September 30, 2024.

(in millions)		Nine Months Ended September 30,
Cash provided by financing activities - 2024	**$**	**2,257**
Net borrowings under credit facilities		3,249
Net borrowings under term loan		1,350
AB 1054 recovery bonds issuance		(1,409)
Short-term debt issuance		(999)
Repayments of long-term debt		(1,125)
Dividend payments		(276)
Proceeds from DWR loan		(980)
Equity contributions from PG&E Corporation		(413)
Other financing activities		220
Net decrease in cash provided by financing activities		**(383)**
Cash provided by financing activities - 2025	**$**	**1,874**

Net cash provided by financing activities decreased by $383 million, or 17%, during the nine months ended September 30, 2025 as compared to the same period in 2024. The decrease was primarily due to:

- $1.41 billion of proceeds related to the issuance of Series 2024-A senior secured recovery bonds in 2024, with no similar transaction in 2025;
- $1.1 billion increase in repayments related to long-term debt;
- $980 million decrease in proceeds related to the DWR loan; and
- $413 million decrease in equity contributions received from PG&E Corporation.

Partially offset by:

- $3.2 billion increase in net borrowings under credit facilities.

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.

LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Notes 10 and 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 and in "Regulatory Matters" below 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.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the OEIS, the Nuclear Regulatory Commission ("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.

During the quarter ended September 30, 2025 and through the date of this filing, key updates to regulatory matters include the following:

- On August 5, 2025, the FERC issued a final order approving an all-party settlement of the Utility's transmission owner rate case for 2024 (the "TO21" rate case).

- On August 28, 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 to Establish Energization Timelines.

- On September 26, 2025, the CPUC issued a final decision approving $1.06 billion in cost recovery in the 2022 WMCE proceeding.

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 balancing accounts with limitations or caps on cost recovery. These accounts, which include the CEMA, WEMA, FRMMA, WMPMA,VMBA, Wildfire Mitigation Balancing Account ("WMBA"), and Microgrids Memorandum Account ("MGMA"), 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 September 30, 2025, the Utility had recorded an aggregate amount of approximately $2.6 billion in costs for the CEMA, WEMA, FRMMA, WMPMA, VMBA, WMBA, and MGMA. Of these costs, approximately $0.2 billion was authorized for recovery and accounted for as current, and $2.4 billion was accounted for as long term as of September 30, 2025. See Note 3 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

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 Condensed Consolidated Financial Statements in Part I, Item 1, and "Wildfire Mitigation and Catastrophic Events Cost Recovery Applications" and "Wildfire and Gas Safety Costs Recovery Application" below.

The Utility's cost recovery proceedings for the costs described above that are pending, have pending appeals, or were completed during the nine months ended September 30, 2025 are summarized in the following table:

Proceeding	Request [1]	Status
2021 WMCE	Revenue requirement of approximately $1.47 billion	Partial settlement agreement to recover $721 million of revenue requirement approved August 2023. Decision authorizing $429 million of revenue requirement for the VMBA related costs adopted December 2024. Application for rehearing related to VMBA costs denied September 2025.
2022 WMCE	Revenue requirement of approximately $1.29 billion	Final decision authorizing $1.06 billion of total cost recovery issued September 2025.
2023 WMCE	Revenue requirement of approximately $1.86 billion	Application filed December 2023. Decision authorizing $944 million of interim rate relief adopted September 2024. Partial settlement filed June 2025.
2024 WMCE	Revenue requirement of approximately $435 million	Application filed November 2024.
2023 WGSC	Revenue requirement of approximately $688 million	Application filed June 2023. Decision authorizing $516 million of interim rate relief adopted March 2024.

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

Wildfire Mitigation and Catastrophic Events Cost Recovery Applications

2021 WMCE Application

On December 27, 2024, the CPUC issued a final decision approving a revenue requirement of $429 million associated with costs recorded to the VMBA. On January 27, 2025, the Utility filed an application for rehearing. On September 18, 2025, the CPUC denied the application for rehearing.

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 consist of $1.2 billion in expenses and $136 million in capital expenditures. On June 8, 2023, the CPUC adopted a final decision granting the Utility interim rate relief of $1.1 billion to be recovered over 12 months, which went into effect July 1, 2023.

On December 22, 2023, the Utility filed an unopposed joint settlement with intervenors for an additional $70 million revenue requirement, which is incremental to the previously approved interim rate relief.

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 disallows $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. The remaining $914 million, plus interest, would be recovered to the extent it is approved after the CPUC issues a final decision. Cost recovery requested in the 2023 WMCE application is subject to the CPUC's reasonableness review, which could result in some or all of the interim rate relief being subject to refund.

On April 14, 2025, the CPUC issued a PD that would extend the statutory deadline in this matter to December 1, 2025.

On June 2, 2025, the Utility filed an unopposed all-party settlement with intervenors for an additional $461 million revenue requirement, which is incremental to the previously approved interim rate relief. If the CPUC adopts the settlement agreement, it would resolve all costs recorded to accounts other than the VMBA. The settlement agreement did not address the Utility's revenue requirement request of $833 million associated with costs recorded to the VMBA, for which cost recovery will be determined separately by the CPUC.

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.

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.

The Utility's forward-looking rate cases that are pending, have pending appeals, or were completed during the quarter ended September 30, 2025 are summarized in the following table:

Rate Case	Request	Status
Energization Timelines OIR	Capital cost cap increase of $3.13 billion for 2025 and 2026	Final decision authorizing $2.38 billion increase for 2025 and 2026 cost cap issued August 2025.
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 following CPUC schedule changes in a scoping memo.
2026 Cost of Capital	Increase ROE to 11.30% and cost of debt to 5.04%	Filed March 2025.
Transmission Owner Rate Case for 2024	Revenue requirement of $2.78 billion for 2024	Accepted December 2023, except as to CAISO adder. Appeal of FERC's order regarding CAISO adder pending at Supreme Court. All other issues resolved August 2025.

Energization Timelines Order Instituting Rulemaking

As previously disclosed, on July 16, 2024, the CPUC issued a final decision approving a memorandum account with interim rate relief for the Utility to recover energization costs incremental to the forecasts of the Utility's Phase 1 2023 GRC, subject to annual caps and reasonableness review in the 2027 GRC application. The overall expenditure cap was set at $2.26 billion for the period of 2024 to 2026. The decision also permitted the Utility to request revisions to the 2025 and 2026 cap amounts under certain conditions. On October 4, 2024, the Utility filed a motion to increase the 2025 and 2026 cap amounts by an aggregate $3.13 billion.

On August 28, 2025, the CPUC issued a final decision that increases the cost cap for 2025 and 2026 by an aggregate $2.38 billion.

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.

The table below compares the portion of CPUC jurisdictional revenue requirements and weighted-average rate base that are requested in the GRC proceeding 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		17.7	73.4
2029		18.7	79.4
2030		19.9	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 each year 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. These applications set the cost of capital, ROE, cost of preferred stock, and cost of debt for the Utility's electric generation, electric distribution, natural gas distribution, and natural gas transmission and storage rate base beginning on January 1, 2026.

In the application, as modified by the Utility's opening brief, the Utility requests the following cost of capital rates:

	Cost	Weight	Weighted Cost
Return on Common Equity	11.30 %	52.00%	5.88%
Return on Preferred Equity	5.52 %	0.30%	0.02%
Return on Long-term debt	5.04 %	47.70%	2.41%

The application also requests CPUC approval of 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. The scoping memo issued by the CPUC provides for a procedural schedule that would provide a final decision in 2025.

Transmission Owner Rate Cases

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 bank 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 results in a reduction in the revenue requirement in 2024 from the effective rate request of $2.78 billion to $2.55 billion. 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%.

Other Regulatory Proceedings

2023-2025 Wildfire Mitigation Plan

The Utility submitted an updated 2025 WMP on April 2, 2024, as directed by the OEIS. On November 19, 2024, the OEIS issued a final approval of the Utility's 2025 WMP update. On January 16, 2025, the CPUC ratified the OEIS's approval.

On December 5, 2024, the Utility filed a change order request to update some of the forecasted work in the WMP for 2025. On February 10, 2025, the OEIS issued a decision approving both initiatives in the change order request.

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.

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 addresses 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. The CPUC is considering revising these guidelines.

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. It became effective on that same day. 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.

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 "Environmental Remediation Contingencies" in Note 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q, as well as Item 1A: "Risk Factors" and Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K.

RISK MANAGEMENT ACTIVITIES

There have been no material changes to the Utility's or PG&E Corporation's risk management activities as previously disclosed in Item 7 of the 2024 Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

There have been no material changes to the Utility's or PG&E Corporation's critical accounting estimates as previously disclosed in Item 7 of the 2024 Form 10-K.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See Note 2 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Operating Revenues				
Electric	$ 4,755	$ 4,538	$ 13,304	$ 13,048
Natural gas	1,495	1,403	4,827	4,740
Total operating revenues	**6,250**	**5,941**	**18,131**	**17,788**
Operating Expenses				
Cost of electricity	1,015	835	2,013	1,919
Cost of natural gas	131	89	738	822
Operating and maintenance	2,641	2,683	8,147	8,076
SB 901 securitization charges, net	35	33	35	33
Wildfire-related claims, net of recoveries	1	74	100	70
Wildfire Fund expense	86	139	271	295
Depreciation, amortization, and decommissioning	1,132	1,059	3,302	3,134
Total operating expenses	**5,041**	**4,912**	**14,606**	**14,349**
Operating Income	**1,209**	**1,029**	**3,525**	**3,439**
Interest income	94	156	392	495
Interest expense	(770)	(795)	(2,296)	(2,322)
Other income, net	97	83	251	241
Income Before Income Taxes	**630**	**473**	**1,872**	**1,853**
Income tax (benefit) expense	(220)	(106)	(161)	15
Net Income	**850**	**579**	**2,033**	**1,838**
Preferred stock dividend requirement	27	3	82	10
Income Available for Common Shareholders	**$ 823**	**$ 576**	**$ 1,951**	**$ 1,828**
Weighted Average Common Shares Outstanding, Basic	**2,198**	**2,137**	**2,197**	**2,136**
Weighted Average Common Shares Outstanding, Diluted	**2,281**	**2,143**	**2,202**	**2,142**
Net Income Per Common Share, Basic	**$ 0.37**	**$ 0.27**	**$ 0.89**	**$ 0.86**
Net Income Per Common Share, Diluted	**$ 0.37**	**$ 0.27**	**$ 0.89**	**$ 0.85**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Net Income	**$ 850**	**$ 579**	**$ 2,033**	**$ 1,838**
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $0, $0 and $0 respectively)	—	—	1	—
Net unrealized (loss) gain on available-for-sale securities (net of taxes of $1, $2, $4 and $1 respectively)	(4)	4	10	3
Total other comprehensive income (loss)	**(4)**	**4**	**11**	**3**
Comprehensive Income	**846**	**583**	**2,044**	**1,841**
Preferred stock dividend requirement	27	3	82	10
Comprehensive Income Available for Common Shareholders	**$ 819**	**$ 580**	**$ 1,962**	**$ 1,831**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions)

	(Unaudited) Balance at	
	September 30, 2025	**December 31, 2024**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 404	$ 940
Restricted cash and restricted cash equivalents (includes $334 million and $263 million related to VIEs at respective dates)	368	273
Accounts receivable		
Customers (net of allowance for doubtful accounts of $408 million and $418 million at respective dates) (includes $2.0 billion and $1.9 billion related to VIEs, net of allowance for doubtful accounts of $407 million and $418 million at respective dates)	2,343	2,220
Accrued unbilled revenue (includes $1.4 billion and $1.3 billion related to VIEs at respective dates)	1,633	1,487
Regulatory balancing accounts	4,827	7,227
Other (net of allowance for doubtful accounts of $82 million and $35 million at respective dates)	1,871	1,810
Regulatory assets	323	234
Inventories		
Gas stored underground and fuel oil	74	52
Materials and supplies	689	768
Wildfire Fund asset	298	301
Wildfire self-insurance asset	1,000	905
Other	563	999
Total current assets	**14,393**	**17,216**
Property, Plant, and Equipment		
Property, Plant, and Equipment	125,271	118,262
Construction work in progress	5,082	4,458
Financing lease ROU asset and other	9	814
Total property, plant, and equipment	**130,362**	**123,534**
Accumulated depreciation	(36,565)	(35,305)
Net property, plant, and equipment	**93,797**	**88,229**
Other Noncurrent Assets		
Regulatory assets	16,283	15,561
Customer credit trust	902	377
Nuclear decommissioning trusts	4,190	3,833
Operating lease ROU asset	462	524
Wildfire Fund asset	3,807	4,070
Other (includes noncurrent accounts receivable of $71 million and $82 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $18 at respective dates)	4,415	3,850
Total other noncurrent assets	**30,059**	**28,215**
TOTAL ASSETS	**$ 138,249**	**$ 133,660**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited) Balance at	
	September 30, 2025	**December 31, 2024**
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,025	$ 1,523
Long-term debt, classified as current (includes $218 million and $222 million related to VIEs at respective dates)	2,769	2,146
Accounts payable		
Trade creditors	3,019	2,748
Regulatory balancing accounts	2,561	3,169
Other	748	748
Operating lease liabilities	87	85
Financing lease liabilities	1	577
Interest payable (includes $156 million and $91 million related to VIEs at respective dates)	657	760
Wildfire-related claims	492	916
Other	3,936	3,658
Total current liabilities	**15,295**	**16,330**
Noncurrent Liabilities		
Long-term debt (includes $11.8 billion and $10.1 billion related to VIEs at respective dates)	55,531	53,569
Regulatory liabilities	20,061	19,417
Pension and other postretirement benefits	834	808
Asset retirement obligations	5,354	5,444
Deferred income taxes	3,777	3,082
Operating lease liabilities	375	439
Financing lease liabilities	5	4
Other	4,787	4,166
Total noncurrent liabilities	**90,724**	**86,929**
Equity		
Shareholders' Equity		
Mandatory convertible preferred stock	1,579	1,579
Common stock, no par value, authorized 3,600,000,000 and 3,600,000,000 shares at respective dates; 2,197,837,402 and 2,193,573,536 shares outstanding at respective dates	31,588	31,555
Reinvested earnings	(1,181)	(2,966)
Accumulated other comprehensive loss	(8)	(19)
Total shareholders' equity	**31,978**	**30,149**
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	**32,230**	**30,401**
TOTAL LIABILITIES AND EQUITY	**$ 138,249**	**$ 133,660**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited)	
	Nine Months Ended September 30,	
	2025	2024
Cash Flows from Operating Activities		
Net income	$ 2,033	$ 1,838
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	3,302	3,134
Bad debt expense	331	244
Allowance for equity funds used during construction	(164)	(136)
Deferred income taxes and tax credits, net	700	684
Wildfire Fund expense	271	295
Other	(84)	258
Effect of changes in operating assets and liabilities:		
Accounts receivable	(454)	(952)
Wildfire-related insurance receivable	(106)	278
Inventories	57	31
Accounts payable	25	541
Wildfire-related claims	(424)	(429)
Other current assets and liabilities	377	(521)
Regulatory assets, liabilities, and balancing accounts, net	1,324	1,658
Other noncurrent assets and liabilities	(432)	(820)
Net cash provided by operating activities	**6,756**	**6,103**
Cash Flows from Investing Activities		
Capital expenditures	(8,631)	(7,541)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,365	1,410
Purchases of nuclear decommissioning trust investments	(1,421)	(1,468)
Proceeds from sales and maturities of customer credit trust investments	310	291
Purchases of customer credit investments	(729)	(477)
Proceeds from self-insurance investments	669	—
Purchases of self-insurance investments	(828)	(449)
Other	15	15
Net cash used in investing activities	**(9,250)**	**(8,219)**
Cash Flows from Financing Activities		
Borrowings under credit facilities	3,080	6,543
Repayments under credit facilities	(1,330)	(8,042)
Borrowings under term loan	500	—
Repayments under term loan	(1,000)	(2,350)
Short-term debt financing, net of issuance of costs of $0 and $1 at respective dates	—	999
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $27 and $13 at respective dates	2,973	3,987
Repayments of long-term debt	(1,925)	(800)
Proceeds from issuance of AB 1054 recovery bonds, net of financing fees of $0 and $10 at respective dates	—	1,409
Repayment of AB 1054 recovery bonds	(72)	(46)
Repayment of SB 901 recovery bonds	(67)	(64)

Common stock dividends paid	(166)	(64)
Mandatory convertible preferred stock dividends paid	(72)	—
Proceeds from DWR loan	—	980
Other	132	(138)
Net cash provided by financing activities	**2,053**	**2,414**
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**(441)**	**298**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at January 1	**1,213**	**932**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at September 30	**$ 772**	**$ 1,230**
Less: Restricted cash and restricted cash equivalents	(368)	(335)
Cash and cash equivalents at September 30	**$ 404**	**$ 895**

Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	$ (2,079)	$ (1,911)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$ 1,416	$ 953
Operating lease liabilities arising from ROU assets	—	6
Financing lease liabilities arising from obtaining ROU assets	—	43
DWR loan forgiveness and performance-based disbursements	95	81
Common stock dividends declared but not yet paid	55	21
Mandatory convertible preferred stock dividends declared but not yet paid	24	—
Capital expenditures financed through current assets and non-current liabilities	592	—

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	Preferred Stock	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non-controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2024	**$ 1,579**	**2,193,573,536**	**$31,555**	**—**	**$ —**	**$ (2,966)**	**$ (19)**	**$ 30,149**	**$ 252**	**$ 30,401**
Net income	—	—	—	—	—	634	—	634	—	634
Other comprehensive income	—	—	—	—	—	—	7	7	—	7
Common stock issued, net	—	4,111,477	(1)	—	—	—	—	(1)	—	(1)
Stock-based compensation amortization	—	—	(22)	—	—	—	—	(22)	—	(22)
Common stock dividends declared	—	—	—	—	—	(55)	—	(55)	—	(55)
Preferred stock dividend requirement	—	—	—	—	—	(27)	—	(27)	—	(27)
Balance at March 31, 2025	**$ 1,579**	**2,197,685,013**	**$31,532**	**—**	**$ —**	**$ (2,414)**	**$ (12)**	**$ 30,685**	**$ 252**	**$ 30,937**
Net income	—	—	—	—	—	549	—	549	—	549
Other comprehensive income	—	—	—	—	—	—	**8**	**8**	—	**8**
Common stock issued, net	—	152,389	—	—	—	—	—	—	—	—
Stock-based compensation amortization	—	—	**28**	—	—	—	—	**28**	—	**28**
Common stock dividends declared	—	—	—	—	—	**(56)**	—	**(56)**	—	**(56)**
Preferred stock dividend requirement	—	—	—	—	—	**(28)**	—	**(28)**	—	**(28)**
Balance at June 30, 2025	**$ 1,579**	**2,197,837,402**	**$31,560**	**—**	**$ —**	**$ (1,949)**	**$ (4)**	**$ 31,186**	**$ 252**	**$ 31,438**
Net income	—	—	—	—	—	850	—	850	—	850
Other comprehensive loss	—	—	—	—	—	—	(4)	(4)	—	(4)
Common stock issued, net	—	70,001	—	—	—	—	—	—	—	—
Stock-based compensation amortization	—	—	28	—	—	—	—	28	—	28
Common stock dividends declared	—	—	—			(55)	—	(55)	—	(55)
Preferred stock dividend requirement	—	—	—	—	—	(27)	—	(27)	—	(27)
Balance at September 30, 2025	**$ 1,579**	**2,197,907,403**	**$31,588**	**—**	**$ —**	**$ (1,181)**	**$ (8)**	**$ 31,978**	**$ 252**	**$ 32,230**

	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, 2023	**2,133,597,758**	**$ 30,374**	**—**	**$ —**	**$ (5,321)**	**$ (13)**	**$ 25,040**	**$ 252**	**$ 25,292**
Net income	—	—	—	—	735	—	735	—	735
Other comprehensive loss	—	—	—	—	—	(1)	(1)	—	(1)
Common stock issued, net	3,558,470	—	—	—	—	—	—	—	—
Stock-based compensation amortization	—	(18)	—	—	—	—	(18)	—	(18)
Common stock dividends declared	—	—	—	—	(22)	—	(22)	—	(22)
Preferred stock dividend requirement of subsidiary	—	—	—	—	(3)	—	(3)	—	(3)
Balance at March 31, 2024	**2,137,156,228**	**$ 30,356**	**—**	**$ —**	**$ (4,611)**	**$ (14)**	**$ 25,731**	**$ 252**	**$ 25,983**
Net income	—	—	—	—	524	—	524	—	524
Common stock issued, net	304,127	—	—	—	—	—	—	—	—
Stock-based compensation amortization	—	23	—	—	—	—	23	—	23
Common stock dividends declared	—	—	—	—	(21)	—	(21)	—	(21)
Preferred stock dividend requirement of subsidiary	—	—	—	—	(4)	—	(4)	—	(4)
Balance at June 30, 2024	**2,137,460,355**	**$ 30,379**	**—**	**$ —**	**$ (4,112)**	**$ (14)**	**$ 26,253**	**$ 252**	**$ 26,505**
Net income	—	—	—	—	579	—	579	—	579
Other comprehensive income	—	—	—	—	—	4	4	—	4
Common stock issued, net	84,499	—	—	—	—	—	—	—	—
Stock-based compensation amortization	—	23	—	—	—	—	23	—	23
Common stock dividends declared	—	—	—	—	(22)	—	(22)	—	(22)
Preferred stock dividend requirement of subsidiary	—	—	—	—	(3)	—	(3)	—	(3)
Balance at September 30, 2024	**2,137,544,854**	**$ 30,402**	**—**	**$ —**	**$ (3,558)**	**$ (10)**	**$ 26,834**	**$ 252**	**$ 27,086**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Operating Revenues				
Electric	$ 4,755	$ 4,538	$ 13,304	$ 13,048
Natural gas	1,495	1,403	4,827	4,740
Total operating revenues	**6,250**	**5,941**	**18,131**	**17,788**
Operating Expenses				
Cost of electricity	1,015	835	2,013	1,919
Cost of natural gas	131	89	738	822
Operating and maintenance	2,636	2,678	8,128	8,062
SB 901 securitization charges, net	35	33	35	33
Wildfire-related claims, net of recoveries	1	74	100	70
Wildfire Fund expense	86	139	271	295
Depreciation, amortization, and decommissioning	1,132	1,059	3,302	3,134
Total operating expenses	**5,036**	**4,907**	**14,587**	**14,335**
Operating Income	**1,214**	**1,034**	**3,544**	**3,453**
Interest income	91	153	384	486
Interest expense	(691)	(721)	(2,059)	(2,125)
Other income, net	97	82	251	240
Income Before Income Taxes	**711**	**548**	**2,120**	**2,054**
Income tax (benefit) expense	(202)	(70)	(100)	90
Net Income	**913**	**618**	**2,220**	**1,964**
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	**$ 910**	**$ 615**	**$ 2,210**	**$ 1,954**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Net Income	**$ 913**	**$ 618**	**$ 2,220**	**$ 1,964**
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $0, $0 and $0 respectively)	—	—	2	1
Net unrealized (loss) gain on available-for-sale securities (net of taxes of $1, $2, $4 and $1 respectively)	(4)	5	10	4
Total other comprehensive income (loss)	**(4)**	**5**	**12**	**5**
Comprehensive Income	**$ 909**	**$ 623**	**$ 2,232**	**$ 1,969**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited) Balance at	
	September 30, 2025	**December 31, 2024**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 253	$ 705
Restricted cash and restricted cash equivalents (includes $334 million and $263 million related to VIEs at respective dates)	367	272
Accounts receivable		
Customers (net of allowance for doubtful accounts of $408 million and $418 million at respective dates) (includes $2.0 billion and $1.9 billion related to VIEs, net of allowance for doubtful accounts of $407 million and $418 million at respective dates)	2,343	2,220
Accrued unbilled revenue (includes $1.4 billion and $1.3 billion related to VIEs at respective dates)	1,633	1,487
Regulatory balancing accounts	4,827	7,227
Other (net of allowance for doubtful accounts of $82 million and $35 million at respective dates)	1,873	1,810
Regulatory assets	323	234
Inventories		
Gas stored underground and fuel oil	74	52
Materials and supplies	689	768
Wildfire Fund asset	298	301
Wildfire self-insurance asset	1,000	905
Other	563	998
Total current assets	**14,243**	**16,979**
Property, Plant, and Equipment		
Property, Plant, and Equipment	125,271	118,262
Construction work in progress	5,082	4,458
Financing lease ROU asset and other	8	814
Total property, plant, and equipment	**130,361**	**123,534**
Accumulated depreciation	(36,565)	(35,304)
Net property, plant, and equipment	**93,796**	**88,230**
Other Noncurrent Assets		
Regulatory assets	16,283	15,561
Customer credit trust	902	377
Nuclear decommissioning trusts	4,190	3,833
Operating lease ROU asset	458	519
Wildfire Fund asset	3,807	4,070
Other (includes noncurrent accounts receivable of $71 million and $82 related to VIEs, net of noncurrent allowance for doubtful accounts of $15 million and $18 at respective dates)	4,254	3,697
Total other noncurrent assets	**29,894**	**28,057**
TOTAL ASSETS	**$ 137,933**	**$ 133,266**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited) Balance at	
	September 30, 2025	**December 31, 2024**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,025	$ 1,523
Long-term debt, classified as current (includes $218 million and $222 million related to VIEs at respective dates)	2,769	2,146
Accounts payable		
Trade creditors	3,016	2,745
Regulatory balancing accounts	2,561	3,169
Other	731	729
Operating lease liabilities	87	85
Financing lease liabilities	1	577
Interest payable (includes $156 million and $91 million related to VIEs at respective dates)	596	667
Wildfire-related claims	492	916
Other	3,663	3,331
Total current liabilities	**14,941**	**15,888**
Noncurrent Liabilities		
Long-term debt (includes $11.8 billion and $10.1 billion related to VIEs at respective dates)	49,912	47,958
Regulatory liabilities	20,061	19,417
Pension and other postretirement benefits	768	741
Asset retirement obligations	5,354	5,444
Deferred income taxes	4,368	3,632
Operating lease liabilities	371	434
Financing lease liabilities	5	4
Other	4,811	4,198
Total noncurrent liabilities	**85,650**	**81,828**
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 800,000,000 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	37,225	35,930
Reinvested earnings	(1,455)	(1,940)
Accumulated other comprehensive loss	(8)	(20)
Total shareholders' equity	**37,342**	**35,550**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 137,933**	**$ 133,266**

See accompanying Notes to the Condensed Consolidated Financial Statements.

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

	(Unaudited)	
	Nine Months Ended September 30,	
	2025	2024
Cash Flows from Operating Activities		
Net income	$ 2,220	$ 1,964
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	3,302	3,134
Bad debt expense	331	244
Allowance for equity funds used during construction	(164)	(136)
Deferred income taxes and tax credits, net	738	760
Wildfire Fund expense	271	295
Other	(121)	208
Effect of changes in operating assets and liabilities:		
Accounts receivable	(456)	(952)
Wildfire-related insurance receivable	(106)	278
Inventories	57	31
Accounts payable	27	530
Wildfire-related claims	(424)	(429)
Other current assets and liabilities	449	(493)
Regulatory assets, liabilities, and balancing accounts, net	1,324	1,658
Other noncurrent assets and liabilities	(429)	(820)
Net cash provided by operating activities	**7,019**	**6,272**
Cash Flows from Investing Activities		
Capital expenditures	(8,631)	(7,541)
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,365	1,410
Purchases of nuclear decommissioning trust investments	(1,421)	(1,468)
Proceeds from sales and maturities of customer credit trust investments	310	291
Purchases of customer credit investments	(729)	(477)
Proceeds from self-insurance investments	669	—
Purchases of self-insurance investments	(828)	(449)
Other	15	15
Net cash used in investing activities	**(9,250)**	**(8,219)**
Cash Flows from Financing Activities		
Borrowings under credit facilities	3,080	6,543
Repayments under credit facilities	(1,330)	(8,042)
Borrowings under term loan	500	—
Repayments under term loan	(1,000)	(1,850)
Short-term debt financing, net of issuance of costs of $0 and $1 at respective dates	—	999
Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $27 and $9 at respective dates	2,973	2,999
Repayments of long-term debt	(1,925)	(800)
Proceeds from issuance of AB 1054 recovery bonds, net of financing fees of $0 and $10 at respective dates	—	1,409
Repayment of AB 1054 recovery bonds	(72)	(46)

Repayment of SB 901 recovery bonds	(67)	(64)
Preferred stock dividends paid	(11)	(10)
Common stock dividends paid	(1,725)	(1,450)
Equity contribution from PG&E Corporation	1,295	1,708
Proceeds from DWR loan	—	980
Other	156	(119)
Net cash provided by financing activities	**1,874**	**2,257**
Net change in cash, cash equivalents, restricted cash, and restricted cash equivalents	**(357)**	**310**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at January 1	**977**	**736**
Cash, cash equivalents, restricted cash, and restricted cash equivalents at September 30	**$ 620**	**$ 1,046**
Less: Restricted cash and restricted cash equivalents	(367)	(334)
Cash and cash equivalents at September 30	**$ 253**	**$ 712**

Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	$ (1,819)	$ (1,735)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$ 1,416	$ 953
Operating lease liabilities arising from obtaining ROU assets	—	1
Financing lease liabilities arising from obtaining ROU assets	—	43
DWR loan forgiveness and performance-based disbursements	95	81
Capital expenditures financed through current assets and non-current liabilities	592	—

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED 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, 2024	**$ 258**	**$ 1,322**	**$ 35,930**	**$ (1,940)**	**$ (20)**	**$ 35,550**
Net income	—	—	—	695	—	695
Other comprehensive income	—	—	—	—	7	7
Equity contribution	—	—	450	—	—	450
Common stock dividend	—	—	—	(575)	—	(575)
Preferred stock dividend requirement	—	—	—	(3)	—	(3)
Balance at March 31, 2025	**$ 258**	**$ 1,322**	**$ 36,380**	**$ (1,823)**	**$ (13)**	**$ 36,124**
Net income	—	—	—	612	—	612
Other comprehensive income	—	—	—	—	8	8
Equity contribution	—	—	325	—	—	325
Common stock dividend	—	—	—	(575)	—	(575)
Preferred stock dividend requirement	—	—	—	(4)	—	(4)
Balance at June 30, 2025	**$ 258**	**$ 1,322**	**$ 36,705**	**$ (1,790)**	**$ (5)**	**$ 36,490**
Net income	—	—	—	913	—	913
Other comprehensive loss	—	—	—	—	(4)	(4)
Equity contribution	—	—	521	—	—	521
Common stock dividend	—	—	—	(575)	—	(575)
Preferred stock dividend requirement	—	—	—	(3)	—	(3)
Balance at September 30, 2025	**$ 258**	**$ 1,322**	**$ 37,226**	**$ (1,455)**	**$ (9)**	**$ 37,342**

	Preferred Stock	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2023	**$ 258**	**$ 1,322**	**$ 30,570**	**$ (2,613)**	**$ (13)**	**$ 29,524**
Net income	—	—	—	781	—	781
Other comprehensive loss	—	—	—	—	(1)	(1)
Equity contribution	—	—	440	—	—	440
Common stock dividend	—	—	—	(450)	—	(450)
Preferred stock dividend requirement	—	—	—	(3)	—	(3)
Balance at March 31, 2024	**$ 258**	**$ 1,322**	**$ 31,010**	**$ (2,285)**	**$ (14)**	**$ 30,291**
Net income	—	—	—	565	—	565
Equity contribution	—	—	265	—	—	265
Common stock dividend	—	—	—	(500)	—	(500)
Preferred stock dividend requirement	—	—	—	(4)	—	(4)
Balance at June 30, 2024	**$ 258**	**$ 1,322**	**$ 31,275**	**$ (2,224)**	**$ (14)**	**$ 30,617**
Net income	—	—	—	618	—	618
Other comprehensive income	—	—	—	—	5	5
Equity contribution	—	—	1,003	—	—	1,003
Common stock dividend	—	—	—	(500)	—	(500)
Preferred stock dividend requirement	—	—	—	(3)	—	(3)
Balance at September 30, 2024	**$ 258**	**$ 1,322**	**$ 32,278**	**$ (2,109)**	**$ (9)**	**$ 31,740**

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED 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 Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed 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 Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility.

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments that management believes are necessary for the fair presentation of PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information as of December 31, 2024 in the Condensed Consolidated Balance Sheets included in this Form 10-Q was derived from the audited Consolidated Balance Sheets in Item 8 of the 2024 Form 10-K. This Form 10-Q should be read in conjunction with the 2024 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, asset retirement obligations, wildfire-related receivables, and pension and other post-retirement benefit plan obligations. Management believes that its estimates and assumptions reflected in the Condensed 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

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 ("CODM") is the Chief Executive Officer of PG&E Corporation.

Net income (loss) is the measure that the CODM 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 Condensed 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 Condensed Consolidated Financial Statements.

PG&E Corporation and the Utility do not have any significant segment expenses because the CODM is not regularly provided with information that is considered to be significant under Accounting Standards Codification ("ASC") 280, Segment Reporting. Except for publicly available information, the information regularly provided to the CODM 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.

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 Condensed 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2025**	**2024**	**2025**	**2024**
Electric				
Revenue from contracts with customers				
Residential	$ 2,306	$ 2,572	$ 5,561	$ 5,887
Commercial	2,249	2,301	5,368	5,461
Industrial	655	707	1,455	1,561
Agricultural	807	802	1,484	1,421
Public street and highway lighting	27	26	80	78
Other, net [1]	(196)	(557)	558	362
Total revenue from contracts with customers - electric	5,848	5,851	14,506	14,770
Regulatory balancing accounts [2]	(1,093)	(1,313)	(1,202)	(1,722)
Total electric operating revenue	**$ 4,755**	**$ 4,538**	**$ 13,304**	**$ 13,048**
Natural gas				
Revenue from contracts with customers				
Residential	$ 490	$ 412	$ 2,629	$ 2,142
Commercial	173	163	794	723
Transportation service only	436	408	1,438	1,307
Other, net [1]	(1)	44	(268)	(158)
Total revenue from contracts with customers - gas	1,098	1,027	4,593	4,014
Regulatory balancing accounts [2]	397	376	234	726
Total natural gas operating revenue	**1,495**	**1,403**	**4,827**	**4,740**
Total operating revenues	**$ 6,250**	**$ 5,941**	**$ 18,131**	**$ 17,788**

[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 September 30, 2025, PG&E Corporation and the Utility 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.

Expected credit losses of $89 million and $331 million were recorded in Operating and maintenance expense on the Condensed Consolidated Statements of Income for credit losses associated with trade and other receivables during the three and nine months ended September 30, 2025, respectively. For the three and nine months ended September 30, 2024, expected credit losses were $109 million and $244 million, 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 September 30, 2025, the RUBA current balancing accounts and FERC noncurrent regulatory asset balances were $219 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. The RUBA current balancing account balance decreased from December 31, 2024 to September 30, 2025 primarily due to the annual electric and gas true-up, which allows the Utility to recover approximately $260 million in undercollections from residential customers in 2025.

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 10 below. Wildfire Fund receivables risk is related to the Wildfire Fund's durability, which is a measurement of its claim-paying capacity. PG&E Corporation and the Utility 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 September 30, 2025, expected credit losses for insurance receivables, Wildfire Fund receivables, and available-for-sale debt securities were immaterial.

Government Assistance

The Utility participated in various government assistance programs during the nine months ended September 30, 2025 and 2024. The Utility's accounting policy is to apply a grant accounting model by analogy to International Accounting Standards 20, *Accounting for Government Grants and Disclosure of Government Assistance*.

DWR Loan Agreement

On October 18, 2022, the DWR and the Utility executed a $1.4 billion loan agreement to support the extension of DCPP, up to approximately $1.1 billion of which could be repaid by funds received from the DOE (see "U.S. DOE's Civil Nuclear Credit Program" below). Under the loan agreement, the DWR paid the Utility a monthly performance-based disbursement equal to $7 for each MWh generated by DCPP, effective September 2, 2022. The aggregate amount of performance-based disbursements under this agreement was $300 million. For more information about the DWR Loan Agreement, see Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K.

The Utility initially accounts 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 Condensed Consolidated Financial Statements:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2025**	**2024**	**2025**	**2024**
Long-term debt:				
Beginning Balance - DWR loan outstanding	$ 808	$ 651	$ 886	$ 98
Proceeds received	—	380	—	980
Operating Expenses:				
Operating and maintenance expense - *Performance-based disbursements*	(2)	(21)	(20)	(60)
Operating and maintenance expense - *Loan forgiveness and other adjustments*	(17)	—	(75)	12
Other current liabilities:				
Change in performance-based disbursements deferred	2	(14)	—	(34)
Long-term debt:				
Ending Balance - DWR loan outstanding	$ 791	$ 996	$ 791	$ 996

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 three and nine months ended September 30, 2025, the Condensed Consolidated Statements of Income reflected $34 million and $134 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 three and nine months ended September 30, 2024, the Condensed Consolidated Statements of Income reflected $71 million and $370 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 nine months ended September 30, 2025, the Condensed Consolidated Statements of Income reflected $57 million, 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 Condensed 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 nine months ended September 30, 2025 or is expected to be provided in the future that was not previously contractually required. As of September 30, 2025 and December 31, 2024, the SPV had net accounts receivable of $3.4 billion and $3.2 billion, respectively, 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 nine months ended September 30, 2025 or is expected to be provided in the future that was not previously contractually required. On November 12, 2021, November 30, 2022, and August 1, 2024, PG&E Recovery Funding LLC issued $860 million, $983 million, and $1.42 billion of senior secured recovery bonds, respectively. As of September 30, 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 Condensed 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 nine months ended September 30, 2025 or is expected to be provided in the future that was not previously contractually required. On May 10, 2022 and July 20, 2022, PG&E Wildfire Recovery Funding LLC issued $3.6 billion and $3.9 billion of senior secured recovery bonds, respectively. As of September 30, 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 Condensed 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 September 30, 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 September 30, 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 the first quarter of 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 September 30, 2025, PG&E Corporation and the Utility recorded $193 million in Other current liabilities, $568 million in Other noncurrent liabilities, $298 million in Current assets - Wildfire Fund asset, and $3.8 billion in Noncurrent assets - Wildfire Fund asset in the Condensed Consolidated Balance Sheets. During the three months ended September 30, 2025 and 2024, the Utility recorded amortization and accretion expense of $86 million and $139 million, respectively. During the nine months ended September 30, 2025 and 2024, the Utility recorded amortization and accretion expense of $271 million and $295 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 Condensed 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 10 below.

Oakland Headquarters Purchase

On June 3, 2025, the Utility completed the purchase of the legal parcel that contains the Lakeside Building (the "Property"). 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 Condensed Consolidated Statements of Cash Flows, and the property assessment and prepayments are included in Supplemental disclosures of noncash investing and financing activities.

Pension and Other Post-Retirement Benefits

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

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2025 and 2024 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
(in millions)	**2025**	**2024**	**2025**	**2024**
Service cost for benefits earned [1]	$ 106	$ 99	$ 9	$ 10
Interest cost	252	229	18	17
Expected return on plan assets	(263)	(254)	(37)	(35)
Amortization of prior service (credit)	(1)	—	1	1
Amortization of net actuarial (gain)	—	—	(6)	(6)
Net periodic benefit cost	**94**	**74**	**(15)**	**(13)**
Regulatory account transfer [2]	(10)	(10)	—	—
Total	**$ 84**	**$ 64**	**$ (15)**	**$ (13)**

[1] A portion of service costs is capitalized pursuant to GAAP.
[2] The Utility recorded these amounts to a regulatory account since they are probable of recovery or refund through rates in future periods.

	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,			
(in millions)	**2025**	**2024**	**2025**	**2024**
Service cost for benefits earned [1]	$ 318	$ 297	$ 28	$ 31
Interest cost	756	687	55	53
Expected return on plan assets	(790)	(761)	(112)	(105)
Amortization of prior service cost (credit)	(2)	(2)	2	2
Amortization of net actuarial loss (gain)	1	1	(17)	(17)
Net periodic benefit cost	**283**	**222**	**(44)**	**(36)**
Regulatory account transfer [2]	(30)	(29)	—	—
Total	**$ 253**	**$ 193**	**$ (44)**	**$ (36)**

[1] A portion of service costs is capitalized pursuant to GAAP.
[2] The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

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

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

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (Loss)

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

(in millions, net of income tax)	Pension Benefits	Other Benefits	Available-for-Sale Securities[2]	Total
	Three Months Ended September 30, 2025			
Beginning balance	$ (34)	$ 18	$ 17	$ 1
Other comprehensive income before reclassification				
Loss on investments (net of taxes of $0, $0 and $1, respectively)	—	—	(4)	(4)
Amounts reclassified from other comprehensive income: [1]				
Amortization of prior service cost (net of taxes of $1, $1, and $0, respectively)	—	—	—	—
Amortization of net actuarial (gain) (net of taxes of $0, $2, and $0, respectively)	—	(4)	—	(4)
Regulatory account transfer (net of taxes of $0, $1, and $0, respectively)	—	4	—	4
Net current period other comprehensive (loss)	**—**	**—**	**(4)**	**(4)**
Ending balance	**$ (34)**	**$ 18**	**$ 13**	**$ (3)**

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. See the "Pension and Other Post-Retirement Benefits" table above for additional details.
[2] Includes amounts related to the customer credit trust and Pacific Energy Risk Solutions, LLC.

(in millions, net of income tax)	Pension Benefits	Other Benefits	Customer Credit Trust	Total
	Three Months Ended September 30, 2024			
Beginning balance	$ (28)	$ 18	$ 1	$ (9)
Other comprehensive income before reclassification				
Gain on investments (net of taxes of $0, $0, and $2 respectively)	—	—	4	4
Amounts reclassified from other comprehensive income: [1]				
Amortization of prior service cost (net of taxes of $1, $1, and $0, respectively)	(1)	1	—	—
Amortization of net actuarial loss (gain) (net of taxes of $0, $2, and $0, respectively)	1	(5)	—	(4)
Regulatory account transfer (net of taxes of $0, $1, and $0, respectively)	—	4	—	4
Net current period other comprehensive gain	**—**	**—**	**4**	**4**
Ending balance	**$ (28)**	**$ 18**	**$ 5**	**$ (5)**

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. See the "Pension and Other Post-Retirement Benefits" table above for additional details.

(in millions, net of income tax)	Pension Benefits	Other Benefits	Available-for-Sale Securities[2]	Total
	Nine Months Ended September 30, 2025			
Beginning balance	$ (35)	$ 18	$ 3	$ (14)
Other comprehensive income before reclassification				
Gain on investments (net of taxes of $0, $0, and $4, respectively)	—	—	10	10
Amounts reclassified from other comprehensive income: [1]				
Amortization of prior service cost (net of taxes of $1, $1, and $0, respectively)	(1)	1	—	—
Amortization of net actuarial loss (gain) (net of taxes of $0, $5, and $0, respectively)	1	(12)	—	(11)
Regulatory account transfer (net of taxes of $0, $4, and $0, respectively)	1	11	—	12
Net current period other comprehensive gain	**1**	**—**	**10**	**11**
Ending balance	**$ (34)**	**$ 18**	**$ 13**	**$ (3)**

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. See the "Pension and Other Post-Retirement Benefits" table above for additional details.
[2] Includes amounts related to the customer credit trust and Pacific Energy Risk Solutions, LLC.

(in millions, net of income tax)	Pension Benefits	Other Benefits	Customer Credit Trust	Total
	Nine Months Ended September 30, 2024			
Beginning balance	$ (28)	$ 18	$ 2	$ (8)
Other comprehensive income before reclassification				
Gain on investments (net of taxes of $0, $0, and $1, respectively)			3	3
Amounts reclassified from other comprehensive income: [1]				
Amortization of prior service cost (net of taxes of $1, $1, and $0, respectively)	(2)	2		
Amortization of net actuarial loss (gain) (net of taxes of $0, $5, and $0, respectively)	1	(13)		(12)
Regulatory account transfer (net of taxes of $0, $4, and $0, respectively)	1	11		12
Net current period other comprehensive gain	**—**	**—**	**3**	**3**
Ending balance	**$ (28)**	**$ 18**	**$ 5**	**$ (5)**

[1] These components are included in the computation of net periodic pension and other post-retirement benefit costs. See the "Pension and Other Post-Retirement Benefits" table above for additional details.

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

Accounting Standards Issued But Not Yet Adopted

Income Taxes

In December 2023, the FASB issued ASU No. 2023-09*, Income Taxes (Topic 740): Improvements to Income Tax Disclosures,* which amends the existing guidance to enhance the transparency and decision usefulness of income tax disclosures. The standard requires consistent categories and greater disaggregation of information in the rate reconciliation, and disaggregation of income taxes paid by jurisdiction. This ASU became effective for PG&E Corporation and the Utility on January 1, 2025. There is no significant impact on PG&E Corporation and the Utility's Condensed Consolidated Financial Statements and related disclosures. PG&E Corporation and the Utility will adopt this new ASU in their Form 10-K for the year ending December 31, 2025.

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 amends 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 Condensed 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 amends 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 Condensed Consolidated Financial Statements and related disclosures.

Financial Instruments-Credit Losses

In July 2025, the FASB issued ASU No. 2025-05, *Financial Instruments—Credit Losses (Topic 326),* which amends the existing guidance to address challenges encountered when applying the guidance in Topic 326, *Financial Instruments—Credit Losses,* to current accounts receivable and current contract assets arising from transactions accounted for under Topic 606, *Revenue from Contracts with Customers.* The amendments in this ASU introduce a practical expedient for all entities and an accounting policy election for entities other than public business entities related to applying Subtopic 326-20 to current accounts receivable and current contract assets arising from transactions accounted for under Topic 606. 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 do not expect the guidance to have a significant impact on their Condensed 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 amends 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 Condensed Consolidated Financial Statements and related disclosures.

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 amends 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. This ASU will become effective for PG&E Corporation and the Utility for fiscal years beginning after December 15, 2026, 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 Condensed Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Noncurrent regulatory assets are comprised of the following:

	Balance at	
(in millions)	**September 30, 2025**	**December 31, 2024**
Pension benefits	$ 693	$ 673
Environmental compliance costs	1,138	1,172
Price risk management	128	167
Catastrophic event memorandum account	673	742
Wildfire-related accounts	1,734	1,697
Deferred income taxes	5,737	4,771
Financing costs	205	216
SB 901 securitization	5,117	5,194
General rate case memorandum accounts	67	95
Other	791	834
Total noncurrent regulatory assets	**$ 16,283**	**$ 15,561**

Regulatory Liabilities

Noncurrent regulatory liabilities are comprised of the following:

	Balance at	
(in millions)	**September 30, 2025**	**December 31, 2024**
Cost of removal obligations	$ 9,339	$ 8,943
Public purpose programs	1,183	1,112
Employee benefit plans	1,103	1,088
Transmission tower wireless licenses	270	306
SFGO sale	20	79
SB 901 securitization	6,103	6,295
Wildfire self-insurance	817	804
Other	1,226	790
Total noncurrent regulatory liabilities	**$ 20,061**	**$ 19,417**

Regulatory Balancing Accounts

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

	Balance at	
(in millions)	**September 30, 2025**	**December 31, 2024**
Electric distribution	$ 959	$ 1,591
Electric transmission	95	117
Gas distribution and transmission	496	387
Energy procurement	1,436	1,066
Public purpose programs	181	162
Wildfire-related accounts	301	979
Insurance premium costs	—	38
Residential uncollectibles balancing accounts	219	260
Catastrophic event memorandum account	244	500
General rate case memorandum accounts	278	1,113
Other	618	1,014
Total regulatory balancing accounts receivable	**$ 4,827**	**$ 7,227**

	Balance at	
(in millions)	**September 30, 2025**	**December 31, 2024**
Electric transmission	$ 244	$ 883
Gas distribution and transmission	51	72
Energy procurement	777	329
Public purpose programs	493	882
SFGO sale	62	93
Wildfire-related accounts	319	337
Nuclear decommissioning adjustment mechanism	—	23
Other	615	550
Total regulatory balancing accounts payable	**$ 2,561**	**$ 3,169**

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K.

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 September 30, 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)	$ —	$ (320)	$ 5,080
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**	**$ (1,750)**	**$ (320)**	**$ 5,730**

(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 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.

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 expects to use the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount 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 expects to use the net proceeds of such issuances for repayment of a portion of its $1.9 billion aggregate principal amount 3.15% First Mortgage Bonds due January 1, 2026. The Utility expects to use 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").

As of September 30, 2025 and December 31, 2024, the Condensed Consolidated Financial Statements reflected the net carrying amount of the Convertible Notes of $2.14 billion and $2.13 billion, respectively, with unamortized debt issuance costs of $15 million and $20 million, respectively, included in Long-term debt. For the three and nine months ended September 30, 2025, the Condensed Consolidated Statements of Income reflected the total interest expense of approximately $23 million and $69 million, respectively. For the three and nine months ended September 30, 2024, the total interest expense recorded was immaterial to the Condensed Consolidated Statements of Income.

For more information about the Convertible Notes, see Note 4 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K. As of September 30, 2025, none of the conditions allowing holders of the Convertible Notes to convert had been met.

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 fixed recovery charges and customer credits are presented on a net basis in Operating revenues in the Condensed Consolidated Statements of Income and had no net impact on Operating revenues for the nine months ended September 30, 2025 and 2024.

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 September 30, 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 Condensed Consolidated Statements of Income. During the three and nine months ended September 30, 2025, the Utility recorded $87 million and $226 million for amortization of the regulatory asset and liability, respectively, in the Condensed Consolidated Statements of Income. During the three and nine months ended September 30, 2024, the Utility recorded $80 million and $241 million for amortization of the regulatory asset and liability, respectively, in the Condensed 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	(77)	(48)
Balance at September 30	**$ 5,117**	**$ 5,201**

	SB 901 securitization regulatory liability	
(in millions)	**2025**	**2024**
Balance at January 1	**$ (6,295)**	**$ (6,628)**
Amortization	303	289
Additions[1]	(111)	(53)
Balance at September 30	**$ (6,103)**	**$ (6,392)**

[1] Includes $76 million and $20 million of returns on investments in the customer credit trust expected to be credited to customers for the nine months ended September 30, 2025 and 2024, respectively.

NOTE 6: EQUITY

Dividends

Subject to the dividend restrictions as described in Note 6 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K, 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.

Utility

On each of November 29, 2024, February 20, and May 22, 2025, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock totaling $3.5 million, which were paid on February 18, May 15, and August 15, 2025, to holders of record as of January 31, April 30, and July 31, 2025, respectively. On September 18, 2025, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock totaling $3.5 million, payable on November 15, 2025, to holders of record as of October 31, 2025.

On each of February 20, May 22, and September 18, 2025, the Board of Directors of the Utility declared common stock dividends of $575 million, which were paid to PG&E Corporation on March 18, May 30, and September 26, 2025, respectively.

PG&E Corporation

On each of November 29, 2024, February 20, May 22, and September 18, 2025, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of $0.025 per share, each declaration totaling $55 million, which were paid on January 15, April 15, July 15, and October 15, 2025, to holders of record as of December 31, 2024, March 31, June 30, and September 30, 2025, respectively.

On December 12, 2024, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.7167 per mandatory convertible preferred share, totaling $23 million, which was paid on February 27, 2025, to holders of record as of February 14, 2025. On each of February 20, 2025 and May 22, 2025, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.75 per mandatory convertible preferred share, each declaration totaling $24 million, which were paid on May 29 and August 28, 2025, to holders of record as of May 15 and August 15, 2025, respectively. On September 18, 2025, the Board of Directors of PG&E Corporation declared a cash dividend in the amount of $0.75 per mandatory convertible preferred share, totaling $24 million, payable on December 1, 2025, to holders of record as of November 14, 2025.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the Income available for common shareholders, basic, by the weighted average number of common shares outstanding, basic. PG&E Corporation's diluted EPS is calculated by dividing the income available for common shareholders, diluted, by the weighted average number of common shares outstanding, diluted. 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 available for common shareholders and weighted average common shares outstanding for calculating diluted EPS:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	**2025**	**2024**	**2025**	**2024**
Numerator:				
Income available for common shareholders, basic	**$ 823**	**$ 576**	**$ 1,951**	**$ 1,828**
Mandatory Convertible Preferred Stock dividends	24	—	—	—
Income available for common shareholders, diluted	**$ 847**	**$ 576**	**$ 1,951**	**$ 1,828**
Denominator:				
Weighted average common shares outstanding, basic[1]	**2,198**	**2,137**	**2,197**	**2,136**
Dilutive effect of Employee stock-based compensation	5	6	5	6
Dilutive effect of Mandatory Convertible Preferred Stock	78	—	—	—
Weighted average common shares outstanding, diluted	**2,281**	**2,143**	**2,202**	**2,142**
Total income per common share:				
Basic	**$ 0.37**	**$ 0.27**	**$ 0.89**	**$ 0.86**
Diluted	**$ 0.37**	**$ 0.27**	**$ 0.89**	**$ 0.85**

[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 amount of options and securities that were antidilutive. For the nine months ended September 30, 2025, the calculation of outstanding common shares on a diluted basis excluded the impacts of the mandatory convertible preferred stock, which was antidilutive.

NOTE 8: 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 Condensed 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 Condensed 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 Condensed 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 Condensed 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**	**September 30, 2025**	**December 31, 2024**
Natural Gas [1] (MMBtus [2])	Forwards, futures, and swaps	274,903,478	179,257,247
	Options	76,780,000	37,717,500
Electricity (MWh)	Forwards, futures, and swaps	7,698,933	8,576,078
	Options	1,036,400	1,663,200
	Congestion Revenue Rights [3]	101,477,325	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 September 30, 2025, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 154	$ (22)	$ 3	$ 135
Noncurrent assets – other	195	—	—	195
Current liabilities – other	(145)	22	—	(123)
Noncurrent liabilities – other	(128)	—	—	(128)
Total commodity risk	**$ 76**	**$ —**	**$ 3**	**$ 79**

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

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 186	$ (16)	$ —	$ 170
Other 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 Condensed 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 September 30, 2025, the Utility satisfied or has otherwise addressed its obligations related to the credit-risk related contingency features.

NOTE 9: 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 September 30, 2025				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Assets:					
Short-term investments	$ 285	$ —	$ —	$ —	**$ 285**
Self-insurance investments					
Short-term investments	1,092	—	—	—	**1,092**
Total Self-insurance investments [2]	**1,092**	**—**	**—**	**—**	**1,092**
Nuclear decommissioning trusts					
Short-term investments	34	—	—	—	**34**
Global equity securities	2,492	—	—	—	**2,492**
Fixed-income securities	1,376	1,122	—	—	**2,498**
Assets measured at NAV	—	—	—	—	**26**
Total nuclear decommissioning trusts [3]	**3,902**	**1,122**	**—**	**—**	**5,050**
Customer credit trust					
Short-term investments	8	—	—	—	**8**
Global equity securities	450	—	—	—	**450**
Fixed-income securities	98	346	—	—	**444**
Total customer credit trust	**556**	**346**	**—**	**—**	**902**
Price risk management instruments (Note 8)					
Electricity	—	12	321	(7)	**326**
Gas	—	16	—	(12)	**4**
Total price risk management instruments	**—**	**28**	**321**	**(19)**	**330**
Rabbi trusts					
Short-term investments	114	—	—	—	**114**
Global equity securities	4	—	—	—	**4**
Life insurance contracts	—	65	—	—	**65**
Total rabbi trusts	**118**	**65**	**—**	**—**	**183**
Long-term disability trust					
Short-term investments	3	—	—	—	**3**
Assets measured at NAV	—	—	—	—	**112**
Total long-term disability trust	**3**	**—**	**—**	**—**	**115**
TOTAL ASSETS	**$ 5,956**	**$ 1,561**	**$ 321**	**$ (19)**	**$ 7,957**
Liabilities:					
Price risk management instruments (Note 8)					
Electricity	$ —	$ 68	$ 185	$ (9)	**$ 244**
Gas	—	20	—	(13)	**7**
TOTAL LIABILITIES	**$ —**	**$ 88**	**$ 185**	**$ (22)**	**$ 251**

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and cash collateral.
[2] Includes $1 billion and $76 million held in Pacific Energy Risk Solutions, LLC and Pacific Casualty Insurance Company, LLC, respectively.
[3] Represents amount before deducting $860 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 8)					
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 8)					
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 and cash collateral.
[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 nine months ended September 30, 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 Condensed 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 8 above.

	Fair Value (in millions) At September 30, 2025				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [1]/Weighted-Average Price [2]**
Congestion revenue rights	$ 278	$ 97	Market approach	CRR auction prices	$ (55) - 54 / 2
Power purchase agreements	$ 43	$ 88	Discounted cash flow	Forward prices	$ 16 - 107 / 55

(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 three and nine months ended September 30, 2025 and 2024, respectively:

	Price Risk Management Instruments	
(in millions)	**2025**	**2024**
Asset balance as of July 1	**$ 136**	**$ 126**
Net realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [1]	—	5
Asset balance as of September 30	**$ 136**	**$ 131**

(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.

	Price Risk Management Instruments	
(in millions)	**2025**	**2024**
Asset balance as of January 1	**$ 199**	**$ 199**
Net realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [1]	(63)	(68)
Asset balance as of September 30	**$ 136**	**$ 131**

(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 September 30, 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 September 30, 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]	$ 5,363	$ 5,697	$ 5,358	$ 5,829
Utility	38,151	35,565	37,812	34,532

[1] As of September 30, 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 September 30, 2025				
Nuclear decommissioning trusts				
Short-term investments	$ 34	$ —	$ —	$ 34
Global equity securities	382	2,142	(6)	2,518
Fixed-income securities	2,495	52	(49)	2,498
Total [1]	**$ 2,911**	**$ 2,194**	**$ (55)**	**$ 5,050**
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 $860 million and $747 million as of September 30, 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 September 30, 2025
Less than 1 year	$ 124
1–5 years	726
5–10 years	594
More than 10 years	1,054
Total maturities of fixed-income securities	**$ 2,498**

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2025**	**2024**	**2025**	**2024**
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 586	$ 366	$ 1,365	$ 1,410
Gross realized gains on securities	124	40	130	151
Gross realized losses on securities	(4)	(11)	(21)	(41)

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 September 30, 2025				
Customer credit trust				
Short-term investments	$ 8	$ —	$ —	$ 8
Global equity securities	344	109	(3)	450
Fixed-income securities	440	5	(1)	444
Total	**$ 792**	**$ 114**	**$ (4)**	**$ 902**
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 September 30, 2025
Less than 1 year	$ 1
1–5 years	132
5–10 years	49
More than 10 years	262
Total maturities of fixed-income securities	**$ 444**

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2025	2024	2025	2024
Proceeds from sales and maturities of customer credit trust investments	$ 114	$ 117	$ 310	$ 291
Gross realized gains on securities	7	—	12	8
Gross realized losses on securities	(3)	—	(14)	(2)

NOTE 10: 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 evaluate which potential liabilities are probable and the related range of reasonably estimated losses and record a charge that reflects their best estimate or the lower end of the range, if there is no better estimate.

Assessing whether a loss is probable or reasonably possible, whether the loss or a range of losses is estimable, and the amount of the best estimate or lower end of the range 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 loss accruals 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.

PG&E Corporation and the Utility are aware of numerous civil complaints related to the following wildfire events and may receive further complaints. However, the applicable statutes of limitations have expired, except for the statutes of limitations applicable to the USFS for the 2021 Dixie fire and the 2022 Mosquito fire, which expire in 2027 and 2028, respectively. 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. 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 September 30, 2025.

Payments (in millions)		
2019 Kincade Fire	$	1,276
2021 Dixie Fire		1,852
2022 Mosquito Fire		81
Total at September 30, 2025	**$**	**3,209**

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 October 15, 2025, 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.

PG&E Corporation and the Utility are also aware of a complaint on behalf of Geysers Power Company, Calpine Corporation, and CPN Insurance Corporation. The court previously scheduled a trial on their claims. Since then, the parties entered into a settlement agreement, and the court vacated the trial date on April 23, 2025.

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 quarter 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). The aggregate liability remained unchanged as of September 30, 2025.

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	**$**	**267**
Accrued Losses		100
Payments		(318)
Balance at September 30, 2025	**$**	**49**

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 September 30, 2025, the Utility received $65 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 Condensed 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 October 15, 2025, PG&E Corporation and the Utility are aware of approximately 186 complaints on behalf of at least 8,919 individual plaintiffs related to the 2021 Dixie fire and expect that they may receive further complaints. The plaintiffs seek damages that include wrongful death, property damage, economic loss, medical monitoring, punitive damages, exemplary damages, attorneys' fees and other damages. 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.

The Collins Pine Company and a group of timber companies filed a complaint against PG&E Corporation and the Utility on April 10, 2024. PG&E Corporation and the Utility answered this complaint on May 28, 2024. In the third quarter of 2025, the parties entered into a settlement agreement.

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 October 15, 2025, 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. After PG&E Corporation and the Utility demurred to the putative class complaint, the court issued an order abating the case unless the plaintiffs amended the complaint, which the plaintiffs did on February 12, 2025. On March 18, 2025, PG&E Corporation and the Utility filed an answer, and on April 18, 2025 filed an amended answer. On April 28, 2025, the plaintiffs filed a demurrer and a motion to strike PG&E Corporation and the Utility's answer. On October 3, 2025, the court overruled plaintiffs' demurrer and denied the motion to strike. The court set December 1, 2025 as the deadline for the plaintiffs to move for class certification.

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). In the second quarter of 2025, PG&E Corporation and the Utility recorded additional charges of $150 million. 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 the third quarter of 2025 of $50 million for an aggregate liability of $2.125 billion (before available recoveries).

PG&E Corporation's and the Utility's accrued estimated losses of $2.125 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 the lower end of the range of 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	**$**	**567**
Accrued Losses		200
Payments		(493)
Balance at September 30, 2025	**$**	**274**

As of September 30, 2025, the Utility recorded an insurance receivable of $523 million for probable insurance recoveries in connection with the 2021 Dixie fire.

The Utility recorded an aggregate Wildfire Fund receivable of $1.125 billion for probable recoveries in connection with the 2021 Dixie fire, of which it had received $609 million as of September 30, 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 September 30, 2025, the Utility also recorded a $96 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 $530 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 October 15, 2025, PG&E Corporation and the Utility are aware of approximately 30 complaints on behalf of at least 2,956 individual plaintiffs related to the 2022 Mosquito fire and expect that they may receive further complaints. 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. On April 24, 2024, PG&E Corporation and the Utility filed cross-complaints against PCWA, alleging that conduct by PCWA was a substantial cause of the 2022 Mosquito fire. The cross-complaints seek property damages, indemnification, attorneys' fees, and other damages. 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 insurance). In the second quarter of 2025, PG&E Corporation and the Utility recorded additional charges of $150 million for an aggregate liability of $250 million (before available insurance). The aggregate liability remained unchanged as of September 30, 2025.

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 or state agencies for state or federal fire suppression costs and damages related to federal land, 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, state, county, or local agencies or damage to land and vegetation in national parks or national forests. As to these damages, PG&E Corporation and the Utility have not concluded that a loss is probable. 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 the lower end of the range of 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	**$**	**82**
Accrued Losses		150
Payments		(63)
Balance at September 30, 2025	**$**	**169**

As of September 30, 2025, the Utility recorded an insurance receivable of $256 million for probable insurance recoveries in connection with the 2022 Mosquito fire, including legal fees. As of September 30, 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 September 30, 2025 are:

Potential Recovery Source (in millions)		**2021 Dixie fire**		**2022 Mosquito fire**
Insurance	$	523	$	256
FERC TO rates		96		7
WEMA		530		54
Wildfire Fund		1,125		—
Probable recoveries at September 30, 2025 [(1)]	**$**	**2,274**	**$**	**317**

(1) Includes legal costs of $143 million and $66 million related to the 2021 Dixie fire and 2022 Mosquito fire, respectively, as of September 30, 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 September 30, 2025, PG&E Corporation and the Utility have recorded total probable insurance recoveries of $523 million and $256 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 Condensed 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	(5)	166	161
Reimbursements	—	(56)	(56)
Balance at September 30, 2025	**$ 22**	**$ 200**	**$ 222**

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 Utility'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 September 30, 2025, the Utility recorded reductions of $96 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 September 30, 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 $530 million and $54 million, respectively, as regulatory assets in the WEMA.

Wildfire Fund Recoveries under AB 1054 and SB 254

On July 12, 2019 and September 19, 2025, AB 1054 and SB 254 became law, respectively. 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 September 30, 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. On December 11, 2024, the OEIS approved the Utility's 2024 application and issued the Utility's 2024 safety certification.

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 Condensed 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 September 30, 2025, PG&E Corporation and the Utility recorded $508 million and $8 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 claims paid by the Wildfire Fund received, for the 2021 Dixie fire since December 31, 2024:

Wildfire Fund Receivable (in millions)		**2021 Dixie fire**
Balance at December 31, 2024	**$**	**756**
Accrued Wildfire Fund recoveries		200
Claims paid by Wildfire Fund		(440)
Balance at September 30, 2025	**$**	**516**

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, and because a class settlement, if any, would be subject to, among other things, approval by the Bankruptcy Court and the District Court, and class members would have the right to opt out of any such settlement.

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.*, respectively. 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 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 by October 30, 2025.

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.

Butte County District Attorney's Office Investigation into the 2018 Camp Fire

Following the 2018 Camp fire, the Butte County District Attorney's Office and the California Attorney General's Office opened a criminal investigation of the 2018 Camp fire.

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

On August 20, 2021, the Butte County Superior Court held a brief hearing on the status of restitution, which involves distribution of funds from the Fire Victim Trust. The Butte County Superior Court has since continued the hearing to November 14, 2025.

NOTE 11: 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 and FERC Matters

2023 WMCE Interim Rate Relief Subject to Refund

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 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. The remaining $914 million, plus interest, would be recovered to the extent it is approved after the CPUC issues a final decision. Cost recovery requested in the 2023 WMCE 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.

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. Accruals for contingencies related to such matters totaled $106 million and $74 million as of September 30, 2025 and December 31, 2024, respectively. These amounts were included in Other current liabilities on the Condensed 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 10 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.

Tax Matters

PG&E Corporation's tax returns have been accepted through 2015 for federal income tax purposes. The Internal Revenue Service ("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. As a result, in the year ended December 31, 2024, PG&E Corporation determined that it is no longer more likely than not that its deduction related to a portion of the customer bill credits would ultimately be sustained. Accordingly, PG&E Corporation has decreased its Income tax benefit by $70 million in the year ended December 31, 2024 related to state and federal income taxes. PG&E Corporation intends to defend itself vigorously as to all costs in this matter.

Environmental Remediation Contingencies

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

	Balance at	
(in millions)	**September 30, 2025**	**December 31, 2024**
Topock natural gas compressor station	$ 331	$ 294
Hinkley natural gas compressor station	102	97
Former MGP sites owned by the Utility or third parties (1)	743	782
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2)	74	76
Fossil fuel-fired generation facilities and sites (3)	17	18
Total environmental remediation liability	**$ 1,267**	**$ 1,267**

(1) Primarily driven by the following sites: San Francisco Beach Street, San Francisco Outside East Harbor, San Francisco East Harbour, San Francisco North Beach and San Francisco Filmore 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 United States Environmental Protection Agency 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 assesses and monitors the environmental requirements on an ongoing basis and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the California Environmental Protection Agency, Department of Toxic Substances Control ("DTSC"), several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability as of September 30, 2025, reflects its best estimate of probable future costs for remediation based on the current assessment data and regulatory obligations. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans, the Utility's time frame for remediation, and unanticipated claims filed against the Utility. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition, and cash flows during the period in which they are recorded. As of September 30, 2025, the Utility expected to recover $1.1 billion of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

Natural Gas Compressor Station Sites

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

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the U.S. Department of the Interior. On April 24, 2018, the DTSC authorized the Utility to build an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. Construction activities began in October 2018, and the initial phase of construction was completed in 2021. Additional phases of construction will continue for several years. It is reasonably possible that the Utility's undiscounted future costs associated with the Topock site may increase by as much as $203 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered primarily through the HSMA, where 90% of the costs are recovered through rates.

Hinkley Site

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take action to meet interim cleanup targets. It is reasonably possible that the Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $122 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers before natural gas became available. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. It is reasonably possible that the Utility's undiscounted future costs associated with MGP sites may increase by as much as $596 million if the extent of contamination or necessary remediation at identified MGP sites is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSMA, where 90% of the costs are recovered through rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites often involve long-term remediation. It is reasonably possible that the Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $76 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSMA, where 90% of the costs are recovered through rates.

Fossil Fuel-Fired Generation Sites

In 1998, the Utility divested its generation power plant business as part of generation deregulation. Although the Utility sold its fossil-fueled power plants, the Utility retained the environmental remediation liability associated with each site. It is reasonably possible that the Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $14 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL and 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 the 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. For more information about the Utility's nuclear insurance coverage, see Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K.

Purchase Commitments

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. As of December 31, 2024, the Utility had undiscounted future expected obligations of approximately $33 billion. See Note 15 of the Notes to the Consolidated Financial Statements in Item 8 of the 2024 Form 10-K. During the nine months ended September 30, 2025, several power purchase and energy storage agreements that were previously signed by the Utility were approved by the CPUC and met major operational milestones, resulting in additional undiscounted future expected obligations of approximately $3.6 billion over the next 25 years.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy commodity prices. PG&E Corporation and the Utility engage in price risk management activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates. See the section above entitled "Risk Management Activities" in Part I, Item 2 and in Notes 8 and 9 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1.

ITEM 4. CONTROLS AND PROCEDURES

As required by Rules 13a-15(b) or 15d-15(b) under the Exchange Act, PG&E Corporation and the Utility carried out an evaluation, under the supervision and with the participation of management, including their respective principal executive officers and principal financial officers, of the effectiveness of the design and operation of their disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures. No matter how well designed and operated, disclosure controls and procedures can provide only reasonable, rather than absolute, assurance of achieving the desired control objectives. Based on the foregoing, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers concluded that such controls and procedures were effective as of the end of the period covered by this Form 10-Q.

There were no changes in internal control over financial reporting that occurred during the three months ended September 30, 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.

PART II. OTHER INFORMATION

ITEM 1. 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, including updates to information reported under Item 3: "Legal Proceedings" of the 2024 Form 10-K, see Notes 10 and 11 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1 and Part I, Item 2: "Litigation Matters."

Each of PG&E Corporation and the Utility has elected to disclose environmental proceedings described in Item 103(c)(3)(iii) of Regulation S-K unless it reasonably believes that such proceeding will result in no monetary sanctions, or in monetary sanctions, exclusive of interest and costs, of less than $1 million.

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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 5. OTHER INFORMATION

During the three months ended September 30, 2025, no director or officer of PG&E Corporation or the Utility adopted or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

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 under the Exchange Act or may constitute "non-Rule 10b5-1 trading arrangements" (as defined in Item 408(c) of Regulation S-K).

ITEM 6. EXHIBITS

EXHIBIT INDEX

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 dated 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 12, 2024 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 12, 2024 (File No. 1-2348), Exhibit 3.2)
4.1		Thirtieth Supplemental Indenture, dated as of September 24, 2025, 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 September 24, 2025 (File No. 1-2348), Exhibit 4.1)
4.2		Thirty-First Supplemental Indenture, dated as of October 2, 2025, 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 September 30, 2025 (File No. 1-2348), Exhibit 4.1)
10.1		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)
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 Officers 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 Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2	*	Certifications of the Chief Executive Officers and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS		XBRL Instance Document
101.SC		XBRL Taxonomy Extension Schema Document
101.CA		XBRL Taxonomy Extension Calculation Linkbase Document
101.LA		XBRL Taxonomy Extension Labels Linkbase Document
101.PRE		XBRL Taxonomy Extension Presentation Linkbase Document
101.DE		XBRL Taxonomy Extension Definition Linkbase Document
104		Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

/s/ CAROLYN J. BURKE

Carolyn J. Burke
Executive Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ STEPHANIE N. WILLIAMS

Stephanie N. Williams
Vice President, Chief Financial Officer, and Controller
(duly authorized officer and principal financial officer)

Dated: October 22, 2025