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

FORM 10-K

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

For the fiscal year ended December 31, 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 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 SW Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

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

(Title of class)	(Trading symbol)	(Name of exchange on which registered)
Common Stock, no par value	POR	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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). Yes ☒ No ☐

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

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. ☐

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2025, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $4,436,840,693. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 10, 2026, there were 115,561,705 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement for its 2026 Annual Meeting of Shareholders, intended to be filed not later than 120 days after the close of its fiscal year.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2025

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DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
BESS	Battery Energy Storage System
Biglow Canyon	Biglow Canyon Wind Farm
BPA	Bonneville Power Administration
Carty	Carty natural gas-fired generating plant
Clearwater	PGE-owned portion of the Clearwater Wind Development in Eastern Montana
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
GRC	General Rate Case for a specified test year
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Federal investment tax credit
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PPA	Power purchase agreement
PTC	Federal production tax credit
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
QF	Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility
RAC	Renewable Adjustment Clause
RCE	Reliability Contingency Event
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Decommissioned Trojan nuclear power plant
Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy
Wheatridge	Wheatridge Renewable Energy Facility

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase and sale, transmission, distribution, and retail sale of electricity to customers in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity, natural gas, and environmental credits in an effort to obtain reasonably-priced power to serve its retail customers, manage risk, and administer its long-term wholesale contracts. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE owns unregulated, non-utility property that it utilizes for its corporate headquarters.

PGE's State-approved service area allocation of 4,000 square miles is located entirely within Oregon and includes 51 incorporated cities. During 2025, the Company added 10,000 customers, and as of December 31, 2025, served a total of approximately 960,000 retail customers.

Available Information

PGE's periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Company's website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K.

Regulation

Federal and State regulation each have a significant influence on PGE's business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Regulatory Accounting

PGE prepares financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as: i) property, plant, and equipment; ii) regulatory assets and liabilities; iii) revenues; iv) certain operating expenses; v) depreciation expense; and vi) income tax expense. GAAP provides for the deferral, or recording of expenses and revenues in periods other than when an unregulated entity would. As a result, the Company may record regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue, or reduce expense, can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future regulatory environment and related accounting guidance. For additional information, see *"Regulatory Assets and Liabilities"* in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

Federal Regulation

Multiple federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), may have regulatory authority over certain aspects of PGE's operations and activities, as further described in the paragraphs that follow.

PGE is a "licensee," a "public utility," and a "user, owner, and operator of the bulk power system," as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGE's BAA does not have a material impact on the Company.

Transmission—PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC.

Reliability and Cybersecurity Standards—The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help maintain and strengthen the reliable planning and operation of the bulk power system.

Natural Gas Pipelines—The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to the Company's three natural gas-fired generating plants located near Clatskanie, Oregon: i) Port Westward Unit 1 (PW1); ii) Port Westward Unit 2 (PW2), and iii) Beaver. In addition, the KB Pipeline serves the North Mist storage facility, which is owned and operated by a local natural gas distribution company, and one additional delivery point for a local manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards and public awareness requirements.

Hydroelectric Licensing—As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the *Generating Facilities* section in Item 2.—"Properties."

Accounting Policies and Practices—PGE prepares periodic and current reports in accordance with GAAP. In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Company's Short-term Debt, see *"Short-term Debt"* in the Debt and Equity section of Liquidity and Capital Resources in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Spent Fuel Storage—The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" and *"Hazardous Material"* in the Environmental Matters section of this Item 1.

State Regulation

PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Company's retail prices and reviews the Company's generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. In addition, PGE is required to develop a Clean Energy Plan (CEP) to be filed in connection with the Company's Integrated Resource Plan (IRP) that articulates the Company's strategy to show continued progress toward emission reduction targets through an equitable transition to a decarbonized grid. The OPUC also regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities.

Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases (GRCs)*. PGE periodically evaluates the need to update its retail electric price structure as part of a comprehensive GRC process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Company's rate base, debt-to-equity capital structure, return on equity, overall rate of return, and customer prices.
- *Annual Power Cost Updates*. The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased in the wholesale market and fuel the Company uses to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income). NVPC is net of wholesale revenues as well as gains and losses on the sale of excess natural gas, included in other operating revenue, that is not used to fuel PGE's generation facilities, both of which are classified as Revenues, net in the consolidated statements of income. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC.
- *Renewable Adjustment Clause mechanism.* The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a GRC, of prudently incurred costs to comply with the RPS.
    - In 2016, the State passed Oregon Senate Bill (SB) 1547, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers' energy supply. For further information on SB 1547, see "*RPS standards and related laws"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

oDuring 2021, the State legislature passed Oregon House Bill (HB) 2021, which established clean energy targets and set out a framework that includes, among other things, the development and submittal of CEPs for investor-owned utilities, including PGE, and Electricity Service Suppliers (ESSs) in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. The CEP may accelerate investment in RPS compliant resources, the cost of which may then be recoverable under the RAC, if the resulting resources are needed for RPS compliance. For further information on HB 2021 and the baseline to which the target reductions apply, see "*HB 2021"* in the Laws and Regulations portion of the Overview section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

•*Wildfire Automatic Adjustment Clause mechanism.* As required by the OPUC, PGE has developed and implemented a Wildfire Mitigation Plan, coordinating activities across the Company and with state-wide stakeholders. PGE strives to improve regional safety by reducing the risk of ignition from PGE assets, while limiting the impacts of public safety power shutoff (PSPS) events and other mitigation activities on customers and increasing the resiliency of PGE assets to wildfire damage. The OPUC has authorized an Automatic Adjustment Clause mechanism that allows the Company to recover a certain level of ongoing, prudent mitigation expenses in customer prices.

Customers and Revenues

PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to Direct Access customers that choose to purchase their energy from an ESS. Although the Company includes such customers in its customer counts and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues for these Direct Access customers include only delivery charges and applicable transition adjustments, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, demand response, conservation measures, and the advancement of technology around distributed generation, including rooftop solar, and storage resources also have an influence on customer demand.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 9% of PGE's total retail revenues or 13% of total retail deliveries during 2025.

PGE's Retail revenues, retail energy deliveries, and average number of retail customers consist of the following:

	Years Ended December 31,					
	2025		2024		2023	
Retail revenues [1] (dollars in millions):						
Residential	$ 1,486	48%	$ 1,457	51%	$ 1,263	52%
Commercial	985	32	924	33	808	33
Industrial	561	18	458	16	368	15
Subtotal	3,032	98%	2,839	100%	2,439	100%
Alternative revenue programs, net of amortization	21	1	(40)	(1)	11	—
Other accrued (deferred) revenues, net	17	1	16	1	(3)	—
Total retail revenues	$ 3,070	100%	$ 2,815	100%	$ 2,447	100%
Retail energy deliveries [2] (MWh in thousands):						
Residential	7,596	34%	7,732	36%	7,952	37%
Commercial	7,015	31	7,024	32	7,178	34
Industrial	7,919	35	6,941	32	6,293	29
Total retail energy deliveries	22,530	100%	21,697	100%	21,423	100%
Average number of retail customers:						
Residential	840,457	88%	829,721	88%	815,920	88%
Commercial	114,912	12	113,942	12	112,667	12
Industrial	286	—	281	—	273	—
Total	955,655	100%	943,944	100%	928,860	100%

(1)Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2)Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

The following table presents additional annual averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Company's base retail prices for these calculations.

	Years Ended December 31,		
	2025	2024	2023
Residential			
Revenue per customer (in dollars):	$ 1,699	$ 1,695	$ 1,481
Usage per customer (in kilowatt hours):	9,038	9,318	9,746
Revenue per kilowatt hour (in cents):	18.79¢	18.19¢	15.20¢
Commercial			
Revenue per customer (in dollars):	$ 8,538	$ 8,067	$ 7,133
Usage per customer (in kilowatt hours):	61,050	61,641	63,713
Revenue per kilowatt hour (in cents):	13.99¢	13.09¢	11.20¢
Industrial			
Revenue per customer (in dollars):	$ 1,959,780	$ 1,627,956	$ 1,347,661
Usage per customer (in kilowatt hours):	27,685,423	24,702,680	23,052,538
Revenue per kilowatt hour (in cents):	7.08¢	6.59¢	5.85¢

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of the weather and seasonal temperature changes lead to variations in both heating and cooling needs. Based on the climate in PGE's service area, the heating season tends to span a longer time period while cooling needs, although robust, are reflected over a shorter span concentrated in the summer months of June through September.

Economic conditions can also affect residential demand as job growth and population increases in PGE's service territory have led to customer growth. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Company's commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can be indicative of changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having limited impact on this customer class. Strength in the high-tech manufacturing and digital service sector, along with new data center facilities coming online, have increased deliveries to industrial customers. Federal and State tax incentives and connectivity both locally and to overseas markets via the transpacific cable have led to strong data center development in PGE's service area.

Customer Choice Programs—In addition to standard cost-of-service pricing, the Company offers different pricing options. Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use, time-of-day, and renewable resource pricing. The Company also offers various energy shifting programs like Peak Time Rebates, Smart Thermostat, and Smart Charging, all of which enable PGE to safely reduce power use on the system during peak demand.

Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS.

PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Company's cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts in aggregate.

PGE is also required to offer to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 average megawatts in total, for unplanned, large, new loads and large load growth at existing sites.

For further information regarding Direct Access deliveries, see "Customers and demand" in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE's customers have a desire for purchasing clean energy, as over 221 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. Oregon's most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area have set similar goals.

The Company's Green Future Impact Program, which allows for customer-provided renewable resources, PGE-provided power purchase agreements (PPAs) for renewable resources, and Company-owned, cost-of-service resources under certain options, enables commercial and industrial customers access to bundled renewable attributes from those resources. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable, integrated power while providing customer choice and a cleaner energy system. The total available capacity under the program is 750 MW. For more information on the Company's PPAs that currently serve the Green Future Impact Program, see *"Green Future Impact Program"* within *Purchased Power* in the Power Supply section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in an effort to balance its supply of power to meet the needs of, and obtain reasonably-priced power for, its retail customers, manage risk, and administer its long-term wholesale contracts through the purchase and sale of electricity, natural gas, and environmental credits. Interconnected transmission systems in the western United States and Canada serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGE's engagement in the wholesale electricity marketplace depends upon numerous factors, including: 1) the relative price and availability of power, whether purchased, generated, or from storage facilities; 2) hydro, wind, and solar conditions; and 3) daily and seasonal retail demand. The Company also participates in the California Independent System Operator's (CAISO) western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 12% of total revenues in 2025, 16% in 2024, and 14% in 2023.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2025, 2024, and 2023.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial and industrial customers is affected by seasonal weather conditions. The Company uses various measures, including heating and cooling degree-days and wind speeds to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a prescribed baseline, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The greater the number of degree-days, the greater the expected demand for electricity.

The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2025	3,549	694
2024	3,662	751
2023	3,845	898
15-year average	3,988	636

The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years. In August 2023, PGE set a new all-time high net system load peak of 4,498 megawatts (MW), surpassing the previous all-time peak that occurred in June 2021. In December 2022, the Company recorded its current winter peak of 4,113 MW.

	Winter Loads			Summer Loads		
	Average	Peak	Month	Average	Peak	Month
2025	2,889	3,879	February	2,666	4,385	August
2024	2,802	3,969	January	2,566	4,367	July
2023	2,756	3,661	January	2,512	4,498	August

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing GRC assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, including high-tech and digital services growth in its service territory, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE utilizes its generating resources, as well as wholesale power purchases from third parties, to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region and purchases and sells environmental credits in the wholesale marketplace. In addition, the Company encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage.

PGE's resource and contracted capacity (in MW) was as follows:

	As of December 31,			
	2025		2024	
	Capacity	%	Capacity	%
Generation:				
Thermal [1]:				
Natural gas	1,827	31	1,818	28
Coal	296	5	296	4
Total thermal	2,123	36	2,114	32
Wind [2]	1,025	17	1,025	16
Hydro [3]	435	7	431	7
Total generation	3,583	60	3,570	55
Purchased power:				
Long-term contracts:				
Hydro [3]	1,024	17	1,270	20
PURPA qualifying facilities [4]	310	5	315	5
Dispatchable standby generation	129	2	129	2
Capacity [5]	250	4	250	4
Wind [2]	403	7	400	6
Solar [6]	219	4	219	3
Biomass	—	—	10	—
Total long-term contracts	2,335	39	2,593	40
Short-term contracts	67	1	333	5
Total purchased power capacity	2,402	40	2,926	45
Total resource capacity	5,985	100	6,496	100

(1)Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant.
(2)Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 30 to 40% of capacity, dependent upon wind conditions.
(3)Capacity represents most favorable operating conditions and differs from expected energy to be generated, which is expected to range from 40 to 50% of capacity, dependent upon river flows.
(4)Capacity represents contracted capacity for PPAs under the Public Utility Regulatory Policies Act of 1978 (PURPA).
(5)Capacity represents a heat rate call option of a natural gas generating station. For more information see "*Natural gas heat rate call option*" below.
(6)Capacity includes 50 MW from the solar component of the Wheatridge Renewable Energy Facility (Wheatridge).

For information regarding actual generating output and purchases for the years ended December 31, 2025 and 2024, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

PGE's generating resources consist of six thermal plants (natural gas- and coal-fired), four wind farms, and seven hydroelectric facilities. The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of natural gas and coal, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

Thermal

The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty).

The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see *"RPS standards and related laws"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Wind

PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW.

Although PGE does not operate the wind component of Wheatridge, located in Morrow County, Oregon, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW, through a PPA.

Although PGE does not operate Clearwater wind energy facility located in Eastern Montana, it owns 75 turbines with a total nameplate capacity of 208 MW and purchases the output of the remaining turbines, with a nameplate capacity of 103 MW, through a PPA.

Hydro

The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River.

PGE has a 50.01% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS has an option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the option is exercised, the CTWS's ownership percentage would exceed 50%. PGE purchases 100% of the CTWS's share of the project output. For more information see *"CTWS"* within *Purchased Power* in this Power Supply section of Item 1.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company utilizes financial instruments such as forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Natural Gas

Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy.

PGE owns 79.5%, and is the operator of record, of the KB Pipeline which provides PGE access to 159,726 Decatherms (Dth) per day of firm natural gas transportation capacity. The KB Pipeline directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operated between British Columbia and New Mexico by Williams Northwest Pipeline. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company.

PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants.

PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver.

To serve Coyote Springs and Carty, PGE has access to 119,500 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing the gas market in Alberta, Canada.

Coal

The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2029. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements, manage risk, and administer its long-term wholesale contracts. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis.

PGE's medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE attempts to mitigate a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Hydro—During 2025, the Company had the following agreements:

- *Public Utility Districts*—PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of certain hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 763 MW of nameplate capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time:
  - 434 MW of capacity under a contract expiring in 2026 in which PGE will purchase a 20% share of the project output and sell varying amounts of energy, in accordance with contract terms, back to the PUD in order to meet their load requirements;
  - 71 MW of average monthly capacity with Douglas County PUD that expires in 2028;
  - 79 MW of capacity under a contract expiring in 2030, with an option to renew until 2032, in which PGE will purchase 10% of the project output; and
  - 179 MW of capacity with Grant County PUD that expires in 2052.
- *CTWS*—PGE has a long-term agreement under which the Company purchases output from the CTWS' interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE paid fixed capacity and energy charges to the CTWS for 100% of its share of the project through 2024. The CTWS exercised their option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte effective January 1, 2022. As a result of the sale, capacity from Company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWS's additional share of the project and payments under the PPA increase proportionately. PGE and the CTWS executed an additional 16-year PPA which began on January 1, 2025, that effectively extended the term from 2024 to 2040 and increased the capacity payments in the extension period.
- *Other*—The remaining capacity is primarily comprised of a contract with Portland Hydro, which expires in 2032, that provides for the purchase of power generated from hydroelectric projects with capacity of 36 MW.

PURPA qualifying facilities—PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within one of the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of energy. As of December 31, 2025, PGE had contracts with 67 online QFs, providing a total of 310 MW of capacity. As of December 31, 2025, PGE had one contract with a QF representing 63 MW of capacity that was not yet operational and in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF must cure its default within a period specified under the contract terms. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years.

The expense and volume of purchases from QFs for the years ended December 31, 2025 and 2024 were as follows:

	2025	2024
PURPA contract expense (in millions)	$ 71	$ 64
MWh purchased under PURPA contracts (in thousands)	770	756
Average cost per MWh from PURPA contracts	$ 92.16	$ 84.65

Expenses incurred related to PURPA contracts are included in PGE's AUT.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can dispatch and monitor customer-owned backup generators to provide NERC-required operating reserves. As of December 31, 2025, there were 77 generators with a total DSG nameplate capacity of 129 MW. PGE continues to pursue expansion of the program through ongoing engagement with customers and incorporation of battery energy storage.

Wind—PGE has four contracts to purchase power generated from renewable wind resources. Although the projects as shown below currently provide PGE a total of 403 MW of capacity, the expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions:

- 25 MW of capacity that expires in 2028;
- 75 MW of capacity that expires in 2035;
- 200 MW of capacity that expires in 2051; and
- 103 MW of capacity that expires in 2053.

Solar—PGE has five contracts representing 219 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other three extend to 2037, 2038, and 2042, respectively. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

PGE estimates within its service territory 370 MW of capacity of customer-sited, third-party owned, solar resources, including solar generation from customer rooftop solar meters, and PGE's community solar program. The expected energy from these solar resources will vary based on solar conditions and customer usage. This capacity is not reflected in the resource and contracted capacity table above.

Green Future Impact Program— PGE has four contracts representing 480 MW of capacity to purchase power generated from renewable resources to support the Green Future Impact Program:

- a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This capacity is reflected within solar purchased power in the resource and contracted capacity table above;
- a 25-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that was placed in service in January 2026. This additional capacity is not yet reflected in the resource and contracted capacity table above;
- a 25-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that was placed in service in January 2026. This additional capacity is not yet reflected in the resource and contracted capacity table above; and
- a 20-year contract with Avangrid Renewables representing 120 MW from a renewable solar facility in Morrow County, Oregon that is expected to be placed in service in September 2026. This additional capacity is not reflected in the resource and contracted capacity table above.

For additional information on the Green Future Impact Program, see "*Customer Choice Programs*" within the Customers and Revenues section of this Item 1.

Natural gas heat rate call option—In order to provide additional dispatchable firm capacity to meet customer demand, PGE has entered into a physical heat rate call option (HRCO) for 250 MW of the capacity, energy, and attributes associated with the facility that expires in 2029. In 2025, a new contract was executed to extend the HRCO through 2034.

Short-term contracts—These contracts are for delivery periods of one month to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Company's generating plants to receive automated dispatch signals from the CAISO for load balancing with other western EIM participants in five-minute intervals.

For additional information regarding PGE's power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Energy Storage

PGE's energy storage portfolio includes approximately 522 MW of capacity, not reflected in the resource and capacity table above. PGE's energy storage resources that are in operation as of December 31, 2025 are primarily as follows:

- *Wheatridge*—The Wheatridge Renewable Energy Facility includes a 30 MW battery component. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE.
- *Sundial (formerly Troutdale Grid)*—PGE entered into a storage capacity agreement for a 200 MW Battery Energy Storage System (BESS) in Troutdale, Oregon. NextEra Energy Resources, LLC owns the resource and sells the capacity to PGE under a 20-year agreement. The project was placed in-service in December 2024.
- *Coffee Creek*—PGE entered into an agreement to construct a 17 MW BESS in Sherwood, Oregon. The project was placed in-service in November 2024, and is owned by PGE.
- *Constable (formerly Evergreen)*—PGE entered into an agreement to construct a 75 MW BESS in Hillsboro, Oregon. The project was placed in-service in December 2024, and is owned by PGE.
- *Seaside Grid*—PGE entered into an agreement to construct a 200 MW BESS in Portland, Oregon. The project was placed in service on July 8, 2025, and is owned by PGE.

Certain other energy storage assets are considered immaterial and are not reflected in the resource and contracted capacity table above.

Future Energy Resource Strategy

PGE's IRP outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. For a detailed discussion of the IRPs and recent procurement activities, see *"Investing in a Clean Energy Future"* within the Overview section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2025, PGE delivered approximately 32 million megawatt hours (MWh) through 1,744 circuit miles of transmission lines operating at or above 57 kilovolts (kV).

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with BPA to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's transmission system is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE provided notice of withdrawal from the Western Power Pool's resource adequacy program known as the Western Resource Adequacy Program (WRAP) in October 2025. The Company has participated in the western EIM for several years and signed an implementation agreement in 2025 to join the CAISO Extended Day Ahead Market (EDAM) as an EDAM Entity in Q4 2026. PGE and EDAM-committed western utilities are developing a resource adequacy program that aligns with the EDAM market with a target operational date of 2028. For further information, see "*Operating Activities*" within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system through PGE's OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2. —"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous materials. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions, in terms of both quantity and rate, among other things. Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are more stringent than federal standards. PGE manages its air emissions at its thermal generating plants by the use of

low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded pursuant to the CAA.

In May 2023, the EPA proposed a successor rule to the prior GHG federal rules, including CAA emissions limits and guidelines for carbon dioxide emissions from fossil-fuel fired power plants based on cost-effective and available control technologies. On April 25, 2024, the EPA released final regulations pertaining to electric generation facilities. On April 8, 2025, the President issued a proclamation, *Regulatory Relief for Certain Stationary Sources to Promote American Energy*, granting a two-year compliance exemption pursuant to CAA Section 112(i)(4) for the EPA's MATS rule. The EPA subsequently notified companies whether their sources had been granted the exemption. Colstrip was granted an exemption until July 8, 2029. Environmental groups have filed court challenges to the MATS exemptions.

On June 11, 2025, to advance the goals of the President's *Unleashing American Energy* executive order, the EPA proposed to repeal the 2024 GHG emissions standards for fossil fuel-fired power plants promulgated under Section 111 of CAA. The EPA also proposed to repeal specific amendments to the updated MATS, that were promulgated in 2024, including the revised filterable particulate matter emissions standard. Additionally, on June 30, 2025, the EPA proposed to update the 2024 ELG Rule to extend compliance deadlines and explore flexibilities to promote reliable and affordable power generation. On February 12, 2026, the EPA revoked the 2009 endangerment finding, thus removing the EPA's authority to regulate GHGs. For further information on the final regulations, see *"EPA Regulations for Electric Generating Facilities"* in the *Laws and Regulations* section of the Overview in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE continues to evaluate the final rules to assess the impact they may have on the Company's continuing investment in Colstrip and on the Company's operation of its existing natural gas fleet. Any impacts could be material. Compliance with the 2024 rules could require material upgrades at Colstrip with proposed compliance dates that may not be achievable or require the use of unproven technology, resulting in significant impacts to costs of Colstrip. If upheld, or not modified by the EPA, the 2024 MATS and GHG Rules would require compliance as early as 2027 and 2032, respectively.

In addition to the EPA's proposed rulemakings, several legal challenges have been filed regarding these rules. In challenges to all three rules, at the EPA's request, the courts have granted stays to allow new EPA leadership to reevaluate the rule. These challenges, or attempts by the federal government to withdraw or modify the regulations, if successful, could affect the applicability to PGE and Colstrip, specifically. Given the uncertainty surrounding applicability of these laws and regulations, PGE cannot reasonably estimate the impact to its results of operations, financial position, and cash flows, however, if the MATS Rule and GHG Rule are ultimately enforced, it would likely result in additional material compliance costs. To the extent these regulations result in increased compliance costs, the Company expects to seek recovery of those costs in customer prices.

HB 2021—In 2021, the Oregon Legislature passed HB 2021, which, among other things, requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline emission level is calculated for each provider by using average annual emissions associated with power generated and purchased for retail load for the years 2010 through 2012. For additional information, see *"HB 2021"* in the *Laws and Regulations* section of the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company expects to seek recovery in customer prices.

For more information regarding GHG emissions and related environmental regulation, including Oregon's RPS and the Company's goals in this area, see *"Renewable Adjustment Clause mechanism"* under *State Regulation* in the Regulation section of this Item 1. and *"Company Strategy"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Water Quality

Under the federal Clean Water Act (CWA), entities that require any federal license or permit to conduct an activity that may result in a discharge to Waters of the United States (WOTUS) must first receive a water quality certification or permit from the state in which the activity will occur, or obtain an appropriate waiver. In Oregon, Montana, and Washington, the environmental regulatory agencies of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. The definition of WOTUS is undergoing significant changes to narrow federal jurisdiction under the CWA following the 2023 *Sackett v. EPA* Supreme Court decision. In November 2025, the EPA and U.S Army Corps of Engineers proposed a new rule to redefine WOTUS, limiting protection under the CWA to "relatively permanent" waters and wetlands with "continuous surface connection." PGE is monitoring these rulemaking proceedings. PGE works continually with state agencies to obtain permits or certificates of compliance needed for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards. State standards and jurisdiction related to Waters of the State remain largely unchanged.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities.

Hazardous Materials

The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act. PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials.

PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For

additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Human Capital Management

PGE's talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented, motivated, and diverse workforce and maintain a culture that reflects PGE's Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety.

Employees and Collective Bargaining Agreements—PGE had 2,877 employees in its workforce as of December 31, 2025, with 666 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement, which expires February 2028, covers 602 employees, and the other, which expires August 2027, covers 64 employees. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce.

Competitive Pay and Benefits—PGE offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees.

Talent Development—PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to increase the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience.

Health and Safety—Management has established an Executive Safety Committee that has oversight of the Company's efforts to create a safe workplace. This committee partners closely with International Brotherhood of Electrical Workers Local No. 125 and has active bargaining unit employees in attendance to voice concerns and suggestions and work with PGE management on solutions for continual improvement of the Company's safety programs and culture. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE also has an Industrial Injury Prevention Specialist (IIPS) and accompanying 24/7 nurse line/injury care program, which focuses on building a culture of total worker health for field employees, providing coaching on ergonomics, muscle care, and acute/chronic injury prevention. The IIPS is also a mid-level medical service provider for employees, providing early intervention and first aid care for employees, focusing on timely and appropriate care for employees. PGE offers a variety of competitive wellness benefits to support physical, mental, social, emotional, and financial well-being. Programs include a digital wellness platform, an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families, financial

education, on-site fitness facilities, volunteer opportunities, company-match on charitable contributions, and tuition reimbursement.

Information about Executive Officers

The following are PGE's current executive officers:

Name	Age	Current Position and Past Five Years Experience	Year Appointed Officer
Larry N. Bekkedahl	64	Senior Vice President, Strategy and Advanced Energy Delivery (December 2023 to present), Senior Vice President, Advanced Energy Delivery (July 2021 to December 2023), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021).	2014
M. Angelica Espinosa	48	Senior Vice President, Chief Legal, Corporate Affairs and Compliance Officer (February 2026 to present), Senior Vice President, Chief Legal and Compliance Officer (June 2023 to February 2026), Vice President, General Counsel (March 2022 to June 2023), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021).	2022
Benjamin F. Felton	55	Executive Vice President, Chief Operating Officer (April 2023 to present), Senior Vice President, Energy Supply at DTE Energy (July 2019 to March 2023).	2023
Juan D. Gallegos	45	Vice President, People and Culture and Chief Human Resources Officer (April 2025 to present), Vice President of Human Resources & Administration at Clearway Energy (January 2024 to April 2025), Vice President of People Experience & HR Technology at Cornerstone Building Brands (September 2022 to December 2023), Chief Talent Strategist North American Customer Fulfillment at Amazon (March 2020 to August 2022).	2025
John T. Kochavatr	52	Vice President, Digital Solutions and Chief Information Officer (July 2024 to present) Vice President, Customer & Digital Solutions and Chief Information Officer (May 2022 to July 2024), Vice President, Information Technology and Chief Information Officer (February 2018 to May 2022).	2018
John C. McFarland	45	Senior Vice President, Commercial and Customer (February 2026 to present),Vice President, Chief Commercial and Customer Officer, (July 2024 to February 2026) Chief Executive Officer at FirstElement Fuel, Inc (May 2022 to June 2024), Vice President and Chief Customer Officer at Portland General Electric Company (April 2019 to May 2022)	2024
Maria M. Pope	60	President (October 2017 to present) and Chief Executive Officer (January 2018 to present).	2009
Joseph R. Trpik	56	Senior Vice President, Finance and Chief Financial Officer (June 2023 to present), Senior Vice President, Chief Accounting Officer at Exelon (May 2022 to June 2023), Senior Vice President, Chief Financial Officer and Treasurer at ComEd (November 2021 to May 2022), Senior Vice President, Chief Financial Officer at Exelon Utilities (June 2018 to November 2021).	2023
Martin K. Wyspianski	49	Vice President, Power Markets & Grid Operations (April 2025 to present), Vice President, Electric Engineering, Electric Asset Management at Pacific Gas and Electric Company (July 2022 to April	2025

	2025), Senior Director, Electric and Gas Acquisition at Pacific Gas and Electric Company (October 2020 to August 2022).

ITEM 1A. RISK FACTORS.

When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGE's business, financial condition, results of operations, or cash flows, or that materially adversely affect PGE's results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGE's business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Company's securities could substantially decline.

BUSINESS AND OPERATIONAL RISKS

The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Company's financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, declining tree health, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, or impair the use of, and damage, the Company's facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load requirements, and procure insurance related to such impacts. The increase in additional costs could also have an adverse effect on cash flow and liquidity. In response to more intense, frequent, and severe weather events and increasing peak loads, PGE may need to make additional investments in generation, transmission, distribution, and energy storage assets to enhance reliability and resiliency. Weather-related events could also cause system constraints or disrupt transmission flows, resulting in decreased reliability for customers. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well as increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction.

Facilities may be exposed to wildfires or cause wildfires, which could disrupt services, hinder the Company's ability to execute its strategic plan, subject the Company to liability and litigation, adversely affect PGE's access to capital and increase costs.

Wildfires of greater size and prevalence, such as those of a magnitude seen in the West Coast in recent years, could negatively affect public safety, the resilience of the electric grid, customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to provide reliable service to its customers, PGE's ability to access the wholesale energy market, PGE's ability to operate its generating facilities and transmission and distribution systems, PGE's costs to maintain, repair, and replace such facilities and systems, and PGE's ability to recover these additional costs. While PGE has wildfire mitigation programs in place, PGE may not be able to effectively implement its wildfire mitigation initiatives or wildfire mitigation initiatives may not be successful or effective in preventing or reducing wildfire-related losses. PGE may be unable to effectively implement a PSPS and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be

able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm.

The lack of legislation limiting wildfire-related liability or providing a wildfire relief fund may impact PGE's credit rating, which could hamper the Company's ability to attract capital and invest in the infrastructure required to meet emissions targets and customer reliability needs. PGE may face barriers to securing cost-efficient contracts if there is a perceived risk of utility financial losses related to wildfire. Business partners may be forced to increase prices to recognize the unresolved financial exposure that PGE presents as a counterparty.

Capital investment and operating expenses related to this risk may not be recoverable through customer prices or insurance proceeds. PGE's insurance coverage may not fully cover all the hazards and liabilities to which PGE is subject. Certain liabilities resulting from wildfires and other risks, may be excluded from PGE's insurance coverage. Insurance costs in the utility industry continue to rise, and the Company may be unable to obtain insurance on acceptable terms or at all. Rising insurance costs and any losses for which PGE is not adequately insured against could have a material, adverse effect on our results of operations and financial position.

Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events could disrupt PGE's operations, require significant expenditures, or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability and transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. The Company is exposed to, and may be adversely affected by, interruptions to its computer and information technology systems and sophisticated cyber-attacks. As with most companies, PGE has experienced attempts to breach the Company's systems, customer accounts and other similar incidents. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Company's computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. Employees could also be potential targets of both physical or cyber attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Company's systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, civil unrest or other similar events that could disrupt operations, cause damage to the Company's generation, transmission, or distribution facilities, impact reliability of the transmission and distribution systems or information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGE's ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGE's facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases. Insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. PGE continuously seeks to maintain a robust program of security and controls, but the impact of a physical or material information technology event could have a material adverse effect on the Company's competitive position, reputation, results of operations, financial condition and cash flows.

Natural or human-caused disasters and other risks could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic, earthquake, accidents, equipment failure, acts of terrorism, civil unrest, acts of vandalism, computer system outages, and other events. Such events, which may be amplified by the fact that PGE's business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight.

Electric utility operations may pose risk to workers, the public, and property, and may have adverse impacts on the environment.

The operation of electric generation, transmission, battery storage, and distribution infrastructure involves inherent risks, including, but not limited to, breakdown or failure of equipment, motor vehicle accidents, fires involving the utility's equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Company's operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety.

These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment, and impairment of PGE's operations, all of which could result in financial losses that would have a material adverse effect on the Company's results of operations and financial condition and reputational harm. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines.

The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions may adversely affect PGE's results of operations.

PGE's workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented under collective bargaining agreements. Workforce management risks include the risk of retaining key employees or attracting and retaining employees skilled in new energy technologies, turnover due to demographic challenges as certain employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. Any turnover will require that the Company attract, train, and retain skilled workers to prevent loss of institutional knowledge or skills gaps. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact.

The construction of new facilities and the modifications or replacements of existing facilities are subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

Long-term increases in both the number of customers and demand for energy, as well as the natural aging of existing infrastructure, will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, tariffs impacting the cost and availability of necessary equipment, supply chain disruption and cost inflation, community opposition, availability of a skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, ability to build or secure transmission, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Supply chain disruption could be exacerbated by government tariffs as well as inflation. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects,

which could eliminate or impair PGE's ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Trade tariffs and related market volatility and supply chain disruptions could increase PGE's operating costs, impair PGE's ability to complete capital projects, and impede access to capital markets.

Recently imposed trade tariffs could negatively impact PGE's financial condition, results of operations, and cash flows. While the impact of these trade tariffs is difficult to predict at this time, economic volatility, supply chain disruption, or cost increases triggered by these trade tariffs could negatively affect PGE's ability to execute its strategic plan. Adverse capital and credit market conditions caused by the new trade tariffs could negatively affect the Company's access to capital, cost of capital, and ability to complete capital projects.

Failure of potential data center or other large load customers to materialize as expected, or materialize and then relocate to other service areas, could result in an inability to recover the costs of certain capital investments or failure to achieve PGE's strategic goals.

PGE's business is impacted by uncertainties associated with increased energy demand or significant accelerated growth in demand due to new data centers or other large load businesses. The Company may enter into arrangements with these or other large load customers and potential customers that require PGE to invest capital and assume credit risk related to such developments and the related generation and transmission investments before PGE receives any potential return. Existing data center or other large load customers may move outside the Company's service area due to pricing offered by PGE, which includes cost of compliance with state policies including cost allocation policies, regulatory constraints, ease of or ability to secure independent generation, and other factors. PGE may be unable to build the infrastructure needed to support large load customers, or such construction may be subject to financing, environmental, or other permitting hurdles. If new data centers or other large load customers do not materialize as forecasted, or if existing data center or other large load customers leave the Company's service area, PGE may not be able to realize its strategic goals and the Company may be left with stranded costs and other effects that could have material adverse impacts on its financial condition, results of operations, and cash flows.

RISKS RELATED TO THE PENDING ASSET PURCHASE ACQUISITION

Failure to complete the Asset Purchase Acquisition (the "Acquisition") could negatively impact the Company's results of operations, financial condition, and the market value of its common stock and debt securities.

The Acquisition is contingent on conditions, including receipt of regulatory approvals, that may not be satisfied, which would result in the failure to complete the Acquisition. If the Acquisition is not completed, or if the Company is unable to secure the external financing necessary for the Acquisition, the Company's ongoing business could be materially adversely affected, and the Company will be subject to a variety of risks potentially impacting business or financial results, including the following:

- the market price of the Company's common stock could decline;
- under certain circumstances, upon termination of the Agreement, the Company may be required to pay a termination fee of $35 million;
- payment of costs incurred in connection with pursuing the Acquisition regardless of whether the Acquisition closes; and
- the Company may experience negative reactions from customers, vendors, employees or other key stakeholders.

An adverse outcome in any litigation or other legal proceedings relating to the Agreement, or the transactions contemplated thereby, could have a material adverse impact on the businesses of PGE or their ability to consummate the transactions contemplated by the Agreement.

The Acquisition could be subject to litigation, shareholder demands, or other legal proceedings, including actions alleging that either party's board of directors breached their respective duties to their shareholders by entering into the Agreement, by failing to obtain a greater value in the transaction for their shareholders or other equity holders or otherwise, or any other claims (contractual or otherwise) arising out of the Acquisition or the transactions related thereto. With respect to such proceedings, and any other litigation or other legal proceedings that are brought against PGE or their respective boards of directors, or subsidiaries in connection with the Agreement, or the transactions contemplated thereby, the respective parties to the proceeding intend to defend against any such claims made therein but may not be successful in doing so. An adverse outcome in such matters, as well as the costs and efforts of a defense even if successful, could have a material adverse effect on the parties' ability to consummate the Acquisition in a timely manner, or at all, or their respective business, results of operation, or financial position, including through the possible diversion of either company's resources or distraction of key personnel.

The Acquisition may not achieve its intended results, including anticipated synergies and cost savings.

Although the Company expects that the Acquisition will result in various benefits, including synergies, cost savings and other financial and operational benefits, there can be no assurance regarding when or the extent to which the Company will be able to realize these synergies, cost-savings or other benefits. Achieving the anticipated benefits, including synergies and cost savings, is subject to a number of uncertainties, including whether the Acquired Business can be operated in the manner PGE intends and whether costs to finance the Acquisition will be consistent with expectations. Costs associated with the transaction, including transition or integration costs, could exceed current estimates, negatively impacting the economics of the Acquisition or impacting the Company's results of operations, financial condition or the market value of its common stock and debt securities. Events outside of the Company's control, including but not limited to regulatory changes or developments, could also adversely affect the realization of the anticipated benefits from the Acquisition. In addition, anticipated costs to achieve the integration of the Business may differ significantly from current estimates. The integration may place an additional burden on management and internal resources, and the diversion of management's attention during the integration process could have an adverse effect on PGE's business, financial condition, and expected operating results.

As a result of the Acquisition, PGE will be subject to the regulatory oversight of Washington state, the scope and size of its business and operations are expected to change substantially, and PGE may not be able to successfully integrate or manage the Acquired Business.

The scope and size of the Company's assets, operations and business will change following consummation of the Acquisition, and the Company will be subject to the regulatory oversight of Washington state. Under the Agreement for the Acquisition, PGE would acquire the Acquired Business currently servicing a service area comprising of approximately 140,000 customers in the Washington counties of Lewis, Yakima, Walla Walla, Columbia, Garfield and Benton, and operating following generation facilities, including related interconnection and other facilities: Chehalis combined cycle gas turbine in Lewis County, Goodnoe Hills Wind in Klickitat County and Marengo I and Marengo II Wind in Columbia County.

Prior to the Acquisition, PGE's assets and operations were primarily concentrated in Oregon and subject to the regulatory oversight of the Public Utility Commission of Oregon (OPUC). The Acquired Business operates in Washington and is subject to the regulatory authority of the Washington Utilities and Transportation Commission (WUTC), among other regulatory agencies and stakeholders, which utilize different regulatory frameworks, rate-making procedures, and environmental mandates.

Management across different jurisdictions requires different strategies and expertise, particularly regarding compliance with Washington's specific clean energy legislation and state-specific customer service requirements.

PGE may not be able to successfully integrate the Acquired Business into its existing operations, or manage these expanded assets effectively. Any such failure could have a material adverse effect on PGE's business, financial conditions and results of operations.

REGULATORY, LEGAL, AND COMPLIANCE RISKS

PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which could affect the Company's operations and costs.

PGE is subject to ongoing regulation by the FERC, the OPUC, and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Company's operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Company's costs.

The OPUC regulates the prices that PGE charges, which is a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters, including the costs to implement wildfire mitigation plans. Prices paid by customers are impacted by commodity prices, costs and capital investments, particularly investments made to meet increased customer demand and meet the state's clean energy goals. Regulators may deny recovery of costs considered imprudently incurred. Regulators have delayed recovery of prudently incurred costs due to affordability concerns. Although the OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. The Company's cost recovery proceedings may not authorize sufficient revenues, or the actual costs could exceed its authorized or forecasted costs. Customer dissatisfaction with prices and national and statewide affordability concerns may result in decreased or delayed recovery of prudently incurred costs. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows.

In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, corporate structure, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties and involve many different parties with sometimes conflicting interests, which can increase regulatory scrutiny. Therefore, management cannot predict with certainty the ultimate outcome of any proceeding. The final resolution of certain matters in which PGE is involved could result in disallowance of capital and operating expenses previously deferred, increased litigation, changes to established regulatory procedures or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations.

There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings," *Regulatory Matters* within the "Overview" of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impacts on the Company's results of operations.

PGE is subject to various environmental laws, regulations, and other standards including federal, state, and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, permitting, GHG emissions such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation, require additional pollution control equipment, require investment in non-emitting resources, force early retirement of assets, and otherwise increase costs and increase capital expenditures.

A portion of PGE's total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGE's financial condition and results of operations. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, changes to and new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company's energy requirements.

Compliance with any new or additional GHG emissions reduction and air quality requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction and air quality requirements is subject to significant uncertainties, including those related to: i) the timing of the implementation of emissions reduction rules; ii) required levels of emissions reductions; iii) requirements with respect to the allocation of emissions allowances; iv) the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and v) PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material.

Changes in federal laws and programs may have an adverse impact on the Company's financial position, results of operations, and cash flows.

Changes in federal laws and programs, either through executive order or legislation, including to tax laws and federal grant programs, may have an adverse impact on the Company's financial position, results of operations and cash flows. PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the OPUC, which could have a negative effect on the Company's financial condition and results of operations.

PGE owns and operates renewable generating facilities and battery storage facilities, which generate federal production tax credits (PTCs) and investment tax credits (ITCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable

tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company's wind facilities resulting in a material adverse impact on PGE's financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. The Inflation Reduction Act of 2022 allows for the sale or transfer of renewable tax credits to other taxpayers. The Company has sold and plans to continue to sell tax credits. PGE's inability to generate, transfer, or sell these credits could have a material impact on results of operations.

PGE's results of operations may be also be materially impacted by indemnification obligations to buyers of certain tax credits. These obligations cover potential losses resulting from PGE's failure to meet PTC and ITC qualifications or transferability requirements under the Internal Revenue Code. While PGE is not responsible for losses due to the buyer's actions, legal tax status, or changes in tax law, any other circumstances leading to indemnification could significantly affect the Company's results of operations.

PGE participates in a federal grant program established for the modernization of energy infrastructure through the Infrastructure Investment and Jobs Act, and some PGE customers receive funds through the CHIPS and Science Act of 2022 to support the domestic production of semiconductors and various federal science agencies. Failure to continue these programs, or revocation of grants or funds allocated through these programs could impact the ability to continue to make certain infrastructure investments, or could result in the customers' demand forecast being lower than anticipated, resulting in stranded assets.

ECONOMIC, FINANCIAL, AND MARKET RISKS

A change in forecasted customer demand for electricity may negatively impact PGE's business.

PGE has experienced load growth in recent years, and projects a significant amount of growth in the future. Significant growth may result in PGE's inability to generate or procure enough energy to meet customer demand. PGE's ability to invest in infrastructure necessary to support growth is dependent on regulatory approvals as is PGE's ability to allocate the costs of growth appropriately to customer classes. Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGE's customers. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions and regulatory outcomes could also result in an increased level of uncollectible customer accounts. The Company's business customers, vendors and service providers could experience cash flow problems and be unable to perform under existing or future contracts and could result in investment in assets to accommodate higher load that are no longer needed.

Customer demand could also be negatively impacted by PGE's ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources and small scale generation projects, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity.

The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGE's revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGE's ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGE's financial condition and results of operations.

Concerns about high prices for PGE's customers could negatively impact PGE's financial condition, results of operations, liquidity, and cash flows.

Prices paid by customers are impacted by commodity prices, operating costs and capital investments. PGE's capital investment plan, increasing procurement of renewable power and energy storage, and the cumulative impact of other public policy requirements place continuing upward pressure on customers' prices. Concerns about affordability could cause the regulators to approve lesser amounts in PGE's ratemaking or cost recovery proceedings, as recently occurred in PGE's 2025 General Rate Case (2025 GRC) proceeding at the OPUC. Regulators may authorize, and have in the past authorized, lower revenues than PGE requested, which could impact the Company's ability to timely recover its operating costs. PGE's level of authorized capital investment could decline as well, resulting in a slower growth in rate base and earnings.

Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan.

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGE's cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects.

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGE's common stock in the public market could cause the market price of PGE's common stock to decline. This could impair the Company's ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related

securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and economic interests.

PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities.

Any new debt financing entered into may involve covenants that restrict operations more than PGE's current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Company's ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Company's access to capital markets and limit or delay the ability to carry out the Company's capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan.

The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGE's debt instruments.

PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGE's Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant.

In addition, the terms of the Company's debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the First Mortgage Bonds (FMBs) are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGE's capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGE's net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2025, $403 million of accumulated net income, as defined in the Indenture, was available for payment of dividends under this provision.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Company's ability to recover costs through customer pricing, the Company's ability to effectively manage risks, the Company's cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGE's control, such as tax reform, the state of the economy, and industry generally. A ratings downgrade could increase fees on PGE's syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or S&P Global Ratings (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity and ability to participate in the wholesale markets.

Under certain circumstances, banks participating in PGE's syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGE's liquidity.

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $750 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the plans. Additionally, changes in interest rates affect PGE's liabilities under the plans. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

The volatility of market prices for power and natural gas could adversely affect PGE's costs and ability to manage its energy supply, which could negatively impact the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGE's contract positions may not be fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses.

PGE plans to enter into the EDAM at the CAISO to mitigate risks associated with price volatility. PGE may experience risks including technology, implementation delays, or failure to achieve the benefits forecasted.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. The Reliability Contingency Event (RCE) mechanism, which operates under the PCAM tariff, allows for cost sharing and deferral of certain costs for specific events, was introduced through the 2024 GRC. This mechanism expired at the end of 2025.

PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGE's risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Company's results of operation and financial condition.

Reduced river flows, unfavorable wind conditions, reduced capacity or degradation of solar panels, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Company's other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs.

Although the application of the PCAM or specific contract terms could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits (RECs) and loss of PTCs related to wind generating resources.

The capacity provided by the Company's generating resources and third-party purchased power may not be sufficient to meet its customers' energy demand requirements and may result in increased GHG emissions.

PGE meets its customers' energy demand requirements based on capacity obtained from its generating facilities and third-party PPAs. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file IRPs with the OPUC that detail the Company's plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG

emissions from the power supply. If the capacity provided by the Company's generating facilities and purchased power is not adequate to meet customers' energy demands, or if customer demand increases beyond forecasts, PGE may be required to purchase more power from third parties, which may not come from non-emitting resources, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets, which could increase GHG emissions. Any failure to obtain adequate capacity to meet customers' energy demand requirements could increase its costs and negatively impact PGE's customer satisfaction, all of which could have an adverse impact on PGE's business and results of operations.

Advances in energy technology could make PGE's business less competitive.

A basic premise of PGE's business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGE's growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, modular nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods.

The electricity industry is undergoing significant change, including increased deployment of distributed energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, electric vehicles and demand response technologies. The deployment of these technologies supports PGE's decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grid's capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. PGE may be unable to effectively adapt to evolving technologies, may invest in technologies that ultimately prove ineffective, and employees and customers may be unable to adapt to technologies needed to advance decarbonization goals, such as demand response programs at scale. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission, and may require the use of traditional generation to provide additional capacity at peak times. If all such costs are not recoverable in prices, PGE could experience material increases in its commodity costs, which could impact PGE's results of operations, financial condition, or cash flows.

It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

Changes in market conditions and environmental laws and regulations could negatively impact PGE's non-utility real estate investments.

PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGE's results of operations.

PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGE's T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation

(ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGE's results of operations.

Stakeholder expectations and standards with respect to PGE's environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk.

Investors, lenders, rating agencies, customers, regulators, state legislatures, employees, and other stakeholders often evaluate companies as corporate citizens based on their ESG programs and metrics. Based on PGE's ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Company's ESG profile. Such actions by investors and lenders could increase PGE's cost of, or access to, capital and financing.

PGE is committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. If efforts around diversity, equity and inclusion are perceived to be insufficient or overdone, PGE may not be able to attract or retain talent, and may be subject to investigations, litigation, and other proceedings. Additionally, the cost of implementing and complying with such ESG programs could be material.

Actions of activist shareholders could have a negative impact on PGE's business.

Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Company's Board of Directors and management. Dealing with such actions could result in disruption to company operations, and divert management's and the Company's board's attention and resources from PGE's business and execution of its strategy.

Such shareholder activism could give rise to perceived uncertainties regarding PGE's future, adversely affecting PGE's business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Company's financial condition and results of operations and could cause fluctuations in the trading prices of its common stock based on market perceptions or other factors.

PGE's business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region.

The Company's industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 1C. CYBERSECURITY.

PGE considers cybersecurity to be a top enterprise risk in PGE's enterprise risk management program. The Company manages this risk through established security policies and governance, regular risk assessments, layered technical controls, access management, security awareness training, and resiliency exercises. As a utility with critical infrastructure, both cyber and physical security will continue to be an important consideration for the Company's future strategy and operations. The Company maintains a cybersecurity program, overseen by a

cross-functional executive committee, that uses a risk-based methodology to support the security of its systems. Additional information about cybersecurity risks and the potential impact to the Company can be found in Item 1A.—"Risk Factors." As of the date of this filing, the Company has not experienced a material cybersecurity incident.

Risk Management

PGE uses the cybersecurity framework established by the National Institute of Standard and Technology, which provides a comprehensive, risk-based approach to managing cybersecurity risk across the lifecycle for managing cybersecurity risk. PGE continuously reviews its cybersecurity practices and makes enhancements to address evolving threats, business changes, and regulatory expectations.

PGE maintains incident response processes designed to support the timely response, containment, investigation, remediation, and recovery from cybersecurity incidents. These processes are tested through periodic functional and tabletop exercises to enhance preparedness and resiliency. The Company also conducts regular reviews, audits, and independent assessments, including periodic penetration testing, to evaluate the effectiveness of its cybersecurity controls and to support continuous improvement.

PGE manages third-party cybersecurity risk through due diligence prior to onboarding, ongoing risk monitoring, and periodic reassessment based on the criticality of the vendor relationship. Vendors that do not meet the Company's security requirements may be subject to additional review or may not be engaged.

Governance

Cybersecurity governance is supported by multiple layers of management oversight and assurance. An enterprise-wide management group operates to evaluate the cybersecurity program's effectiveness. The Company has an employee who functions as a Chief Security Officer, whose responsibilities include cybersecurity and who has a reporting relationship to senior management. This employee has had a twenty-five year career with the Federal Bureau of Investigation (FBI) prior to joining the Company. She served as the Confidential Advisor to the Director of the FBI, providing strategic advice across all threats allowing her to develop unique and key insights into the global cyber threat landscape, FBI cyber strategy, and cyber operations. Prior to joining the Company, she served as the Special Agent in Charge of the FBI Jacksonville Division where she led all FBI cyber investigations and operations for nation state and criminal actors.

PGE has a management-level committee, the Integrated Security Executive Committee (ISEC), which focuses specifically on cybersecurity and security-related risks. The ISEC meets quarterly and reviews risks, processes, and strategies related to cybersecurity. Members of the ISEC include; the Chief Information Officer; the Chief Financial Officer; the Vice President, Utility Operations; the Senior Vice President, Advanced Energy Delivery; the Vice President, People and Culture and Chief Human Resources Officer; the Chief Executive Officer; the Chief Legal and Compliance Officer; and other executives as needed. In addition, as a top enterprise risk, cybersecurity is also reviewed by the Company's management-level Executive Risk Committee on an annual basis, or more frequently if circumstances warrant. This broader review allows the cybersecurity risk and mitigations to be aligned with other enterprise risks, including identifying areas of overlap. Members of the Executive Risk Committee include: the Chief Executive Officer; the Chief Legal and Compliance Officer; the Chief Financial Officer; the Chief Operating Officer; the Chief Information Officer; the Vice President, Chief Commercial and Customer Officer; the Senior Vice President of Strategy and Advanced Energy Delivery; the Vice President of Power Markets and Grid Operations; and the Senior Director, Treasurer.

The Audit and Risk Committee of the Board of Directors has oversight of cybersecurity risk and receives briefings on a quarterly basis. The briefings are provided either by the cybersecurity team, together with a senior member of management, or are presented as part of the Audit and Risk Committee's regular review of top enterprise risks, in which cybersecurity risk is reviewed annually or more frequently if circumstances warrant. The Audit and Risk Committee briefs the full Board of Directors at each meeting. In addition, the full Board of Directors has participated in cybersecurity exercises. The Audit and Risk Committee is also provided with information about external assessment results and action plans. There is a process in place to notify the Audit and Risk Committee promptly in the event of a material cybersecurity incident.

Training and Awareness

All employees are required to complete annual physical security and cybersecurity awareness training. The Company conducts ongoing security awareness activities, including cybersecurity training, monthly and targeted phishing campaigns, to reinforce employee vigilance and promote secure behavior. Results from these activities are used to inform continuous improvement efforts.

PGE engages with third parties to monitor the PGE external attack surface and conducts ongoing penetration testing. These assessments support a continuous improvement. As a NERC registered entity, PGE is audited by WECC. The FERC will conduct an audit of cybersecurity controls at PGE hydro facilities in 2026.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are generally located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The Indenture securing the Company's FMBs constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2025 (in MW):

Facility	Location	Capacity
Wholly-owned:		
Natural Gas or Oil [1]*:*		
Beaver	Clatskanie, Oregon	516
Carty	Boardman, Oregon	426
Port Westward Unit 1	Clatskanie, Oregon	403
Coyote Springs	Boardman, Oregon	257
Port Westward Unit 2	Clatskanie, Oregon	225
Wind [2]*:*		
Biglow Canyon	Sherman County, Oregon	450
Tucannon River	Columbia County, Washington	267
Clearwater	Custer County, Montana	208
Wheatridge	Morrow County, Oregon	100
Hydro [3]*:*		
North Fork	Clackamas River	56
Faraday	Clackamas River	46
Oak Grove	Clackamas River	42
River Mill	Clackamas River	25
T.W. Sullivan	Willamette River	18
Jointly-owned [4]**:**		
Coal:		
Colstrip [5]	Colstrip, Montana	296
Hydro [3]*:*		
Round Butte [6]	Deschutes River	187
Pelton [6]	Deschutes River	61
Capacity		3,583

(1)Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility.
(2)Represents nameplate ratings. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.
(3)Represents most favorable operating conditions, which refers to the set of optimal circumstances under which a power plant or energy generation system can achieve its maximum output capacity efficiently and reliably.
(4)Represents PGE's ownership share.
(5)PGE has a 20% ownership interest in the facility, which is operated by Talen Montana, LLC.
(6)PGE has a 50.01% ownership interest in the Pelton/Round Butte hydroelectric project.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the FPA. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

Energy Storage Facilities

The following are energy storage facilities owned by PGE as of December 31, 2025 (in MW):

Facility	Location	Capacity
Seaside BESS	Multnomah County, Oregon	200
Constable BESS	Washington County, Oregon	75
Coffee Creek BESS	Washington County, Oregon	17
Other BESS facilities	Various	9
Total Energy Storage Capacity		301

Transmission and Distribution

PGE owns or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2025, the PGE-owned electric transmission system consisted of 1,744 circuit miles as follows: 287 circuit miles of 500 kV line; 414 circuit miles of 230 kV line; 577 miles of 115 kV line; and 466 miles of 57 kV line. The Company also has 29,251 circuit miles of distribution lines that deliver electricity to its customers. PGE also has an ownership interest in, and capacity on, the following:

- 14% of the 2,260 MW transmission facilities between the Colstrip switchyard and the Broadview switchyard, near Billings, Montana, and 16% of the 1,930 MW transmission facilities between the Broadview switchyard and the interconnection point with BPA's transmission system near Townsend, Montana; and
- 20% of the Northwest AC Intertie, a 4,800 MW transmission facility between the John Day Substation, near the Columbia River in northern Oregon, and Malin, Oregon, near the California border. The Northwest AC Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to a total of 4,335 MW of BPA's transmission systems, and 300 MW of Northwestern Energy's transmission systems.

Non-utility Real Estate

PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. As of December 31, 2025, the non-utility property, plant, and equipment balance, net of accumulated depreciation was $76 million, recorded in Other noncurrent assets on the Company's consolidated balance sheets in Item 8.— "Financial Statements and Supplementary Data."

PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGE's T.W. Sullivan hydro generating facility. PGE has recorded a non-utility ARO related to this site. For more information regarding the Company's AROs, see "*Asset Retirement Obligations*" within the "*Critical Accounting Policies and Estimates"* section of Item 7.— "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

ITEM 3. LEGAL PROCEEDINGS.

See Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data," for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

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

PGE's common stock is traded under the ticker symbol "POR" on the NYSE. As of February 10, 2026, there were 1,096 holders of record of PGE's common stock.

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

For information with respect to securities authorized for issuance under equity-based plans, see Note 13, Equity-based Plans and Note 14, Stock-Based Compensation in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 6. [RESERVED]

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

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future results of operations, business prospects, loads, outcome of litigation and regulatory proceedings, capital expenditures, market conditions, events or performance, and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "may," "plans," "predicts," "projects," "will," "continue," "should," "based on," "considers," "could," "expected," "forecast," "goals," "needs," "promises," "subject to," "strategic imperatives," "targets," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE's expectations, beliefs, or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with forward-looking statements, risks, uncertainties and other important factors that could cause actual results or outcomes for PGE to differ materially from those discussed in such forward-looking statements include:

- New or revised governmental policies, executive orders, legislative actions, and regulatory audits, investigations and actions, including those of the FERC, the OPUC, and the Internal Revenue Service with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs, and capital investments, energy trading activities, tax credits, and current or prospective wholesale and retail competition;

•uncertainties associated with increased energy demand or significant accelerated growth in demand due to new data centers, including the concentration of data centers, and the ability to obtain regulatory approvals, environmental, and other permits to construct new facilities in a timely manner;

•economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;

•increases to operating costs that could result from changes to trade tariffs, rising inflation and volatility in interest rates;

•the impacts of changes in the tax code, including tax rates, minimum tax rates, adjustments made to deferred tax assets and liabilities, and changes impacting the availability of and ability to transfer tax credits;

•risks and uncertainties related to current or future All-Source Request for Proposals (RFP) projects, including, but not limited to regulatory processes, transmission capabilities, system interconnections, inflationary impacts, supply chain constraints, supply cost increases (including application of trade tariffs), permitting and construction delays, available tax credits, counterparty credit risk, and legislative uncertainty;

•changing customer expectations and choices that may reduce customer demand for PGE's services may impact the Company's ability to make and recover its investments through prices and earn its authorized return on equity, including the impact of growing distributed and renewable generation resources, changing customer demand for enhanced electric services, and an increasing risk that customers procure electricity from registered ESSs or the adoption of community choice aggregation;

•the timing or outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Regulatory Matters of the "Overview" in this Item 7. and Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;

•natural or human-caused disasters and other risks, including, but not limited to, earthquake, flood, ice, drought, extreme heat, lightning, wind, fire, accidents, equipment failure, acts of terrorism, computer system outages and other events that disrupt PGE operations, damage PGE facilities and systems, cause the release of harmful materials, cause fires, and subject the Company to liability;

•severe weather and other natural phenomena, such as the greater size and prevalence of wildfires in Oregon in recent years, which could affect public safety, customers' demand for power, and PGE's financial health and ability and cost to procure adequate power and fuel supplies to serve its customers, access the wholesale energy market, or operate its generating facilities and transmission and distribution systems, and the Company's costs to maintain, repair, and replace such facilities and systems, and recovery of such costs;

•ignitions caused by PGE assets or PGE's ability to effectively implement a PSPS and de-energize its system in the event of heightened wildfire risk or implement effective system hardening programs, the inability of which could lead to potential liability if energized systems were involved in wildfires that cause harm, as well as the risk that damages from wildfires may not be recoverable through prices or insurance, resulting in impact to the financial condition or reputation of the Company;

•impacts from legislative action limiting wildfire-related liability or providing a wildfire relief fund, such as negative effects on PGE's credit rating, which could limit PGE's ability to access capital on terms similar to past transactions or at all and could impact PGE's liquidity, cash flows, and capital expenditure plans;

•operational factors affecting PGE's power generating and battery storage facilities, including forced outages, fires, unscheduled delays, environmental impacts, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;

•default or nonperformance on the part of any parties from whom PGE purchases fuel, capacity, or energy, that may cause the Company to incur costs to purchase replacement power and related renewable attributes at increased costs;

•complications arising from PGE's jointly-owned plant, including changes in ownership, change in regulatory requirements, adverse regulatory outcomes or legislative actions, or operational failures that result in legal or environmental liabilities or unanticipated costs related to replacement power, capital improvements, repair costs, or abandoned costs;

•delays in the supply chain and increased supply costs, failure to complete capital projects on schedule or within budget, failure to obtain permits, inability to complete negotiations on contracts for capital projects, failure of counterparties to perform under agreements, or the abandonment of capital projects, any of which could result in the Company's inability to recover project costs, or impact PGE's competitive position, market share, or results of operations in a material way;

•volatility in wholesale power and natural gas prices, including but not limited to volatility caused by macroeconomic and international issues, that could require PGE to post additional collateral or issue additional letters of credit pursuant to power and natural gas purchase agreements;

•changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes, including the potential impact of trade tariffs, on the Company's power costs;

•capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, volatility of equity markets as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, the repayments of maturing debt, and stock-based compensation plans, which are relied upon in part to retain key executives and employees;

•future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;

•changes in, compliance with, and general uncertainty around environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;

•the effects of climate change, whether global or local in nature, including unseasonable or extreme weather and other natural phenomena that may affect energy costs or consumption, increase the Company's costs, cause damage to PGE facilities and system, or adversely affect its operations;

•changes in residential, commercial, or industrial customer growth, or demographic patterns, including changes in load resulting in future transmission constraints, in PGE's service territory;

•the effectiveness of PGE's risk management policies and procedures;

•cybersecurity attacks, data security breaches, physical attacks and security breaches, or other malicious acts, internally or to third parties, that cause damage to the Company's generation, transmission, or distribution facilities, impact information technology systems, inhibit the capability of equipment or systems to function as designed or expected, or result in the release of confidential customer, vendor, employee, or Company information;

•reputational damage from negative publicity, protests, fines, penalties and other negative consequences resulting in regulatory or legal actions;

•employee workforce factors, including potential strikes, work stoppages, transitions in senior management, the ability to recruit and retain key employees and other talent, and turnover due to macroeconomic trends such as voluntary resignation of large numbers of employees;

- failure to achieve the Company's GHG emission goals or being perceived to have either failed to act responsibly with respect to the environment or effectively respond to legislative requirements concerning GHG emission reductions, any of which could lead to adverse publicity and have adverse effects on the Company's operations and/or damage the Company's reputation;
- the impact of widespread health developments, and responses to such developments (such as voluntary and mandatory quarantines, including government stay at home orders, as well as shut downs and other restrictions on travel, commercial, social, and other activities), which could materially and adversely affect, among other things, demand for electric services, customers' ability to pay, supply chains, personnel, contract counterparties, liquidity, and financial markets;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- acts of war, terrorism, or civil disruption; and
- uncertainties associated with the proposed Acquisition, including but not limited to, the expected closing of the proposed transaction and the timing thereof, the financing of the proposed transaction, strategies and plans, opportunities and anticipated future performance and capital structure, and expected accretion to earnings per share and free cash flow.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's consolidated financial statements contained in this report, and other periodic and current reports filed with the SEC.

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the State. The Company participates in wholesale markets by purchasing and selling electricity, natural gas, and environmental credits in an effort to meet the needs of, and obtain reasonably-priced power for, its retail customers, manage risk, and administer its long-term wholesale contracts. In addition, PGE continues to develop products and service offerings for the benefit of retail and wholesale customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory in the State.

Company Strategy

PGE's corporate strategy places customers at the center of everything the Company does. PGE supports energizing lives, strengthening communities, and driving advancement in energy to promote social, economic, and environmental progress. With a focus on affordability, the Company continuously innovates, streamlines, and manages costs to deliver exceptional experiences for its customers. The Company is committed to delivering steady growth and returns to shareholders. The Company is building an increasingly smart, integrated, and interconnected grid that spans from residential customers to other utilities within the region.

PGE is focused on the following strategic imperatives:

- *Decarbonize Power*—make progress toward customer-driven clean energy goals by continuing to add new renewable resources and products to the Company's energy mix;

- *Electrify the Economy*—power the lives of approximately two million residents in its service territory by supporting the region's economic growth industries and capturing the benefits of new technologies while serving approximately two-thirds of Oregon's commercial and industrial activity; and
- *Advance Performance*—build a safer and more reliable grid by accelerating cost-effective grid investments and modernizing transmission.

Pending Acquisition

On February 15, 2026, PGE, through a newly formed, wholly-owned subsidiary, entered into an agreement (the "Agreement") with PacifiCorp, an indirect subsidiary of Berkshire Hathaway Energy Company, to acquire select Washington state generation, transmission, and electric utility operations for $1.9 billion. The Acquisition would enable PGE to extend its service to approximately 140,000 Washington customers.

Under the Agreement, if the Acquisition is completed, PGE will acquire three generation facilities: the Chehalis thermal plant (477 MW), the Goodnoe Hills wind facility (94 MW), and the Marengo I and II wind facilities (234 MW). The Acquisition would also include 4,500 miles of transmission and distribution lines, and local utility operations across approximately 2,700 square miles.

PGE intends to manage the Washington operations as a separate company through a newly created subsidiary regulated by the Washington Utilities and Transportation Commission. PGE intends to retain current Washington employees and honor existing labor agreements. PGE corporate functions are expected to provide shared support for both Washington and Oregon companies.

The Acquisition is designed with the goal that Washington and Oregon customers would not be impacted by costs associated with executing the acquisition and transaction financing. PGE expects the Acquisition and state and federal regulatory reviews to close in approximately twelve months following the submission of regulatory applications.

Central to this Acquisition is PGE's plan to enter into a joint venture with Manulife Infrastructure Fund III, L.P. and its affiliates, including John Hancock Life Insurance Company (U.S.A.), which will collectively be a minority owner of the Washington utility business. PGE would remain majority owner and sole operator.

For a more information regarding PGE's plans to fund its future capital requirements, including this proposed Acquisition, see "Liquidity" in the Liquidity and Capital Resources section of this Item 7. See Note 21, Subsequent Events, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data" for additional information on the pending acquisition.

Climate Change

State-mandated GHG emissions reduction targets—In 2021, the Oregon legislature passed HB 2021, establishing a 100% clean electricity by 2040 framework for PGE and other investor-owned utilities and ESSs in the State. A number of provisions in the bill align with PGE's strategic direction, and highlight Oregon's ambitious, economy-wide goals to combat climate change. The GHG emissions reduction targets applicable to these regulated entities are an 80% reduction in GHG emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For more information regarding HB 2021 and the baseline to which the target reductions apply, see *"HB 2021"* in the "Laws and Regulations" section of this Overview.

Empowering customers and communities—PGE's customers have a desire for purchasing clean energy, as over 221 thousand residential and small commercial customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. In 2017, Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100% clean and renewable

electricity by 2035 and 100% economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area have similar goals and continue to consider similar goals for the future.

The Company implemented a customer subscription option, the Green Future Impact Program, which is a renewable energy program that allows large business and municipal customers to have a choice in how they source their electricity. Under the Green Future Impact Program, customers can enroll in a Customer-Supplied Option (CSO) or PGE-Supplied Option (PSO). Under the CSO, participants are responsible for finding a renewable energy facility that meets established requirements and bringing those resources to PGE. Under the PSO, customers who enrolled in Phase I can receive energy from PGE-provided PPAs for renewable resources and customers who enroll in Phase II can receive energy either from PGE-provided PPAs for renewable resources or energy from renewable resources that are PGE owned, under certain conditions.

As of December 31, 2025, the Green Future Impact Program has an approved capacity of 750 MW nameplate, of which 482 MW have been subscribed. Through this voluntary program, the Company seeks to support customers' clean energy acceleration.

Severe weather—In recent years, PGE's service territory has experienced unprecedented heat, historic ice and snowstorms, and wildfires. In December 2025, Portland, Oregon experienced the warmest December on record, averaging six degrees above normal temperatures for the region. In January 2024, the Company's service territory encountered a severe winter weather event, including snow, ice, and high winds that caused catastrophic damage to physical assets and resulted in widespread customer power outages. For more information regarding the January 2024 severe winter weather event, see "Declared States of Emergency" within this Overview section. In August 2023 the region experienced a record-breaking heat wave with temperatures reaching all-time recorded highs for the month. This resulted in a peak load demand of 4,498 MW, exceeding the Company's previous all-time peak load demand, and surpassing the prior summer peak load by nearly six percent. The increase and severity of weather events highlights the importance of combating the effects of climate change through decarbonizing the power supply and investing in a more reliable and resilient grid.

Investing in a Clean Energy Future

The Resource Planning Process—PGE's resource planning process includes working with customers, stakeholders, and regulators to chart the course toward a clean, affordable, and reliable energy future. With the passage of HB 2021, PGE created a Clean Energy Plan (CEP), which articulates the Company's strategy to make continued progress towards the 2030, 2035, and 2040 emission reduction targets through an equitable transition to a decarbonized grid. The CEP is based on, and was submitted to the OPUC in connection with, the Company's 2023 Integrated Resource Plan (IRP) in March 2023, the first combined IRP and CEP. That filing projected PGE's resource and capacity needs over the next 20 years and proposed an Action Plan to meet near-term needs, subject to HB 2021 emissions reduction requirements.

On June 18, 2025, PGE submitted a CEP/IRP Update to the OPUC. The CEP/IRP Update identified a new Preferred Portfolio as a result of the refreshed analysis. PGE did not propose any changes to the Action Plan that was acknowledged within the 2023 CEP/IRP, which supports the Company's progress toward emissions targets and Preferred Portfolio resource need procurement through the 2025 All-Source RFP. This approach represents the best combination of cost, risk, community benefit, and decarbonization.

To better distinguish resource needs, the CEP/IRP Update reports the capacity from hybrid solar and battery storage resources by individual technology. The capacity need is 3,500 to 4,500 MW of renewable energy and non-emitting capacity, inclusive of 2023 RFP projects, which remain under negotiation.

The actions summarized in the CEP/IRP Update will also serve as an important tool in furthering conversations with all stakeholders, and the OPUC, on PGE's path forward to making continued progress towards emission targets while continuing to serve customers safely, reliably, and at the lowest cost possible. PGE and parties will work through the regulatory review process for the CEP/IRP Update filing (OPUC Docket LC 80) during the coming months. PGE cannot predict the ultimate outcome of the regulatory process.

2023 All-Source RFP

After a robust and competitive bidding, repricing, and negotiating process as part of the 2023 RFP, PGE has entered into agreements to construct two solar and battery hybrid projects for a total of 615 MW:

- Biglow Optimization—PGE entered into an agreement to construct a 125 MW solar facility and a 125 MW BESS in Sherman County, Oregon. PGE will own the resource with an investment of approximately $540 million, excluding AFUDC. The project has an estimated commercial operation date at the end of 2027.
- Wheatridge Expansion—PGE and NextEra Energy, Inc. entered into agreements to construct a 240 MW solar facility and a 125 MW BESS facility, located in Morrow County, Oregon. PGE will own 110 MW of solar and 65 MW of BESS production capacity with an investment of approximately $490 million, excluding AFUDC. NextEra Energy, Inc. will operate the facility, own the remaining 130 MW of solar and 60 MW of BESS production capacity and sell their portion of the output to PGE under a 30-year PPA. The project has an estimated commercial operation date at the end of 2027.

These agreements represent the final procurement from the 2023 All-Source RFP. The 2023 RFP is a component of PGE's multi-pronged procurement approach focused on customer affordability, system reliability, and decarbonization. Both the 2023 RFP reprice and the 2025 RFP disclosed below were designed to capture expiring tax credits to support customer affordability. Additional resources are anticipated to be procured through future acquisition processes, including, but not limited to, PPAs, including a bilateral all-call for PPAs, community-based renewable energy procurement, the ongoing 2025 RFP, and future RFPs.

Additional Procurement Activities

PGE has entered into the following agreements outside of the Company's 2023 RFP and for each has requested the OPUC to grant a waiver to Oregon's competitive bidding rules:

- Meadowlark BESS—a 20-year storage capacity agreement for a 200 MW BESS located in Washington County, Oregon. This project will be owned by Copenhagen Infrastructure Partners, LLC and has an estimated commercial operation date at the end of 2027, pending OPUC approval of the requested waiver of the competitive bidding rules.
- Nottingham BESS—a 20-year storage capacity agreement for a 200 MW BESS located in Washington County, Oregon. This project has an estimated commercial operation date in 2028, pending OPUC approval of the requested waiver of the competitive bidding rules.

2025 All-Source RFP

PGE filed notice with the OPUC in November 2024 that an RFP in 2025 was needed to procure resources to meet a forecasted 2029 capacity shortfall and to make continued progress toward decarbonization targets under HB 2021. These actions were consistent with the 2023 IRP Action Plan and CEP Update. PGE filed the draft 2025 All-Source RFP on April 17, 2025, and regulatory approval was granted on July 22, 2025. The Company issued the RFP to market on July 31, 2025, seeking bids for resources that can provide non-emitting dispatchable capacity and renewable generation.

After a robust and competitive bidding process performed in accordance with Oregon's competitive bidding rules, and with the active participation of, and oversight by, an OPUC-selected third-party independent evaluator, PGE

plans to submit a request for acknowledgement of the final shortlist of bidders to the OPUC. The final shortlist is made up of both renewables and non-emitting capacity projects, as shown in the table below:

		2025 RFP Final Shortlist		
Project	**Technology**	**Structure**	**MW**	**Company-owned MW**
1	Battery	PPA	185	
2	Battery	PPA	200	
3	Wind	PPA	560	
4	Solar	PPA	100	
5	Wind	PPA	103	
6	Solar, Battery	Hybrid	800	400
7	Wind, Battery, Solar	Hybrid	800	375
8	Solar, Battery	BTA	450	450
9	Solar, Battery	BTA	400	400
10	Battery	BTA	100	100
11	Battery	BTA	200	200
12	Solar, Battery	PPA	900	

The proposals for renewable resources provide various combinations of wind, solar and battery storage options that include storage capacity and PPAs along with Company-owned resources via Build Transfer Agreements (BTA). The proposals for non-emitting dispatchable capacity resources provide battery storage options that include PPAs along with Company-owned resources via BTAs.

PGE is proceeding to commercial negotiations with projects on the final shortlist, prioritizing those that include renewable generation and that have a viable pathway to achieve commercial operations earlier in the 2028 - 2030 eligibility period. The ultimate outcome of the RFP process may involve the selection of multiple projects for both renewable and non-emitting dispatchable capacity resources, which PGE expects will be approximately 2,500 MWs in total.

PGE anticipates the OPUC to consider acknowledgement of the RFP final shortlist in May 2026. Additional details of the 2025 RFP (OPUC Docket UM 2371) are available on the OPUC website at www.oregon.gov/puc.

Legal Challenges to the RFP Process

Various regulatory and legal challenges directed at the OPUC have been initiated by NewSun Energy LLC, related to PGE's RFP process. PGE has joined the proceedings as an intervenor, and the challenges are in various stages of litigation or regulatory review. PGE cannot predict the outcome of these proceedings or potential impact, if any.

Transmission Upgrades

In alignment with local and regional transmission plans, the 2023 IRP Action Plan, and CEP Update, PGE is evaluating and implementing upgrades to existing transmission resources and expansions of current transmission networks. Transmission resource actions are intended to alleviate congestion, improve regional adequacy and reliability, enable decarbonization goals, and address growing customer demand.

In May 2024, PGE signed a non-binding memorandum of understanding in the development of the North Plains Connector, an approximately 415-mile, high-voltage direct-current (HVDC) transmission line to be constructed with endpoints near Bismarck, North Dakota and Colstrip, Montana. The parties entered negotiations with the United States Department of Energy (U.S. DOE) to finalize the project objectives, terms, and conditions, including the Company's participation, which is expected to involve a 20% ownership share of the approximately $3.2 billion total investment of the project. In August 2024, the project was awarded a $700 million grant from the U.S. DOE's Grid Resilience and Innovation Partnerships program to further support its development and

would reduce the overall total investment of the project. A portion of the GRIP funding is also allocated to assess upgrades to the Colstrip Transmission System. See "*Federal Grants*" in the Laws and Regulations section of this Overview for further discussion over the impacts of Federal grants and effect of Presidential executive orders.

The North Plains Connector would be the nation's first HVDC transmission connection among three regional U.S. electric energy markets, providing additional flexibility and the sharing of resources across multiple time zones. PGE's resource planning process indicates the need for transmission to provide additional transfer capacity, access to diverse energy resources, and enhanced wholesale markets, and ease congestion on the existing western transmission system. PGE continues to explore the North Plains Connector as a resource to meet those load-service needs.

The U.S. DOE selected the CTWS, with PGE as a subrecipient under the grant, for a $250 million grant to upgrade the existing 230 kV Bethel-Round Butte Transmission line to 500 kV. The project (Warm Springs Power Pathway) will accelerate the development of transmission capacity, enabling new generation in Central and Eastern Oregon to reach customer demand loads in Western Oregon. The added capacity and associated upgrades will also increase resiliency of the transmission system as well as resiliency of the CTWS communities by increasing resources available to the CTWS to support economic growth opportunities. See "*Federal Grants*" in the Laws and Regulations section of this Overview for further discussion over the impacts of Federal grants.

Building a resilient grid—To serve communities with clean energy, PGE's grid of the future will need to be smart and adaptive. Highlights of PGE's key investments and plans for building a resilient grid include:

- *Wildfire Mitigation*—PGE has a Wildfire Mitigation Program under which an annual Wildfire Mitigation Plan is developed and submitted to the OPUC, as required by State law, to coordinate activities across the Company and with State-wide stakeholders. On December 31, 2025, PGE filed its 2026-2028 Wildfire Mitigation Plan, which forecasts $47 to $50 million annually in operations and maintenance costs and an additional $70 to $84 million annually in capital investments, for the 2026-2028 period, to continue system hardening efforts, expand situational awareness capabilities, implement specific inspection and maintenance along with vegetation management, raise community and customer awareness, and take operational actions within high fire risk zones. PGE strives to improve regional safety by mitigating the risk that PGE's electric utility infrastructure could cause a wildfire, while limiting the impacts of PSPS events and other mitigation activities on customers and increasing the resiliency of PGE assets to wildfire damage. During 2025, PGE invested $56 million in capital projects related to wildfire mitigation and resiliency and utility asset management.

- *Virtual Power Plant (VPP)*—PGE's VPP is comprised of Distributed Energy Resources and flexible loads that are managed through technology platforms to provide grid and power operations services. PGE's customer offerings related to flexible load programs, rooftop solar, battery storage, and electric vehicle (EV) charging solutions support grid reliability and increase portfolio flexibility and resource diversity. When coordinated through the Company's Distributed Energy Resources Management Systems, Distributed Energy Resource and flexible loads support cost-effective decarbonization, advance customer and community energy resiliency, promote customer engagement with the energy system, and unlock additional grid services that enhance PGE's operation of a dynamic two-way system. As customer participation in PGE's VPP grows, their actions provide increasing benefit and help avoid customer service interruptions and reduce exposure to scarcity pricing in energy markets.

- *Grid Enhancing Technologies (GETs)*—Limited network upgrades or non-wires solutions are important strategies that offer incremental improvements and can unlock capacity on existing transmission paths in the region. GETs include advanced conductors and coatings, topological optimization, and dynamic line ratings. PGE is actively incorporating GETs across its system to further increase the performance of new and existing transmission assets. These efforts, when deployed across a number of areas and assets, have the potential to add incremental capacity to the grid at lower costs.

- *Distribution System Plan (DSP)*—In 2021 and 2022, PGE filed its inaugural DSP in two parts, which were accepted by the OPUC in March 2022 and February 2023, respectively. The OPUC Staff finalized their review of modifications to the current DSP guidelines in the fourth quarter of 2024 and PGE filed its

next DSP in December 2024, fully compliant with the updated requirement. The DSP outlines distribution system assets, describes how the Company plans for new load, including distributed resources such as EVs and rooftop solar installations, and presents the vision for modernizing the grid to enable accelerated decarbonization and customer participation in demonstrating continual progress towards PGE's clean energy goals. For further information on recovery of costs related to the DSP, see "*Distribution System Plan recovery mechanism*" in the Regulatory Matters section of this Overview.

Electrify the economy—To help Oregon reach its decarbonization goals, PGE is committed to increasing electrification of buildings and supporting vehicle electrification for customers.

Transportation electrification (TE) is one of the most significant ways to reduce GHG emissions in Oregon. PGE is engaged with customers and communities to manage EV charging load, develop infrastructure projects aimed at improving accessibility to EV charging stations, build electric fleet partnerships, and offer programs to support customers' transitions to TE.

In October 2023, the OPUC accepted PGE's second TE plan, which covers the 2023 to 2025 time period and considers current and planned activities, along with forecasted EV loads. To date, PGE has incurred $14 million in capital expenditures under the 2023-2025 TE plan.

On July 25, 2025, PGE filed with the OPUC its draft 2026-2028 TE plan, which represents a continuation of the approach and strategy found within PGE's 2023-2025 TE plan.

On December 9, 2025, the OPUC accepted PGE's 2026-2028 TE plan. In the 2026-2028 period covered by the 2026-2028 TE Plan, capital expenditures are expected to be approximately $11 million.

PGE continues to pursue advanced technologies to enhance the grid, pursue energy storage, and develop microgrids and the use of data and analytics to better predict demand and support energy-saving customer programs.

Laws and Regulations

Trade Tariffs—Recently, trade tariffs were imposed through presidential executive orders. While some tariffs scheduled to take effect were temporarily suspended, broad tariffs remain in effect. Trade tariffs may increase the cost of imported materials and equipment, disrupt supply chains, drive economic volatility, and create adverse capital and credit market conditions. The cost of steel utility poles, meters, transformers, and specialized electrical equipment, among other items, may increase materials and supplies balances and elevate the cost of capital projects. Similarly, prices may rise and lead times may lengthen for necessary components in resources considered for acquisition in PGE's All-Source RFPs. For further information on the Company's RFPs, see "*The Resource Planning Process*" in the Investing in a Clean Energy Future section of this Overview. While PGE's Canadian natural gas imports are not expected to be impacted by the current state of trade tariffs due to the imports being U.S.-Mexico-Canada Agreement compliant, the future of trade tariff impacts on such imports is uncertain. The Company is unable to reasonably estimate the effects of the rapidly evolving trade tariff landscape, as those effects could include project delays and cost increases, and present obstacles to PGE's strategic plan execution. PGE is closely monitoring the impacts of trade tariffs and the potential effect they may have on the Company's financial position, results of operations, or cash flows.

Federal Grants—PGE continues to evaluate opportunities on behalf of customers to leverage state, federal and private foundation funding programs to offset the cost of projects. These projects target improvements in electrical system reliability and resiliency, wildfire situational awareness and mitigation, greater communications capabilities, advancements in customer usage analytics using artificial intelligence, renewable resources and advanced electrical grid support, hydro generation operations, and regional transmission capacity constraints.

On October 2, 2025, PGE received notice from the U.S. DOE of the termination of four federal grants that originally planned to provide $61 million in federal reimbursement over the life of the grants. PGE has incurred an immaterial amount of costs associated with the terminated grants and does not expect the termination process to result in a material impact on the Company's financial position and results of operations.

PGE has been awarded five additional grants totaling approximately $252 million, either as a direct recipient or subrecipient. These grants remain in various stages of execution, with the largest being the Warm Springs Power Pathway. PGE continues to monitor these grants for potential modification or termination but has not received any formal notice of termination. To date, PGE has incurred only immaterial costs related to these grants. See "*Transmission Upgrades*" in the Investing in a Clean Energy Future section of this Overview for further discussion on the Warm Springs Power Pathway grant. The Company cannot predict the ultimate timing and success of securing funding from federal programs or predict the outcome of existing grants.

Inflation Reduction Act of 2022 (IRA)—The IRA was signed into law in August 2022 with a majority of the provisions effective for tax years beginning after December 31, 2022.

The United States Treasury and the Internal Revenue Service released extensive rules addressing credit transfer eligibility and application, including but not limited to, required registration, filing, and documentation for transferors and transferees to elect and claim a credit transfer. See the "*Income Taxes*" section of Note 2, Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" for information on OPUC approval and treatment of tax credit transfers.

PGE has entered into agreements to transfer 2023 through 2025 tax credits and transferred $179 million and $112 million, net of discounts, for cash proceeds in 2025 and 2024, respectively.

The One Big Beautiful Bill Act—The OBBB significantly amends or repeals several renewable-energy tax incentives originally enacted under the IRA. Projects placed in service during 2025 that met applicable tax credit qualification requirements received PTC or ITC benefits, which are reflected in the Company's consolidated financial statements. The transferability of tax credits, as provided under the IRA, also remains in effect. Following the July 7, 2025 executive order that added uncertainty with respect to the specific actions necessary to demonstrate a project's start of construction, on August 15, 2025, the Treasury Department issued a notice for establishing the beginning of construction for wind and solar projects. The notice requires large projects to satisfy a physical-work test after September 2, 2025, eliminates certain inventory-procurement safe harbors, and accelerates the placed in service deadline to December 31, 2027.

These changes, together with the repeal of the permanent ten percent ITC, as outlined in the OBBB, are expected to reduce or eliminate the availability of RECs on future projects. The Company cannot yet reasonably estimate the impact on PGE's results of operations, financial position, and cash flows or on future capital expenditures, deferred tax assets, current and future All-Source RFPs, and customer prices.

See "*The Resource Planning Process*" in the Investing in a Clean Energy Future section of this Overview for information regarding the impact of the OBBB on the RFP process.

HB 2021—Among other things, HB 2021 requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers to certain targets: 80% reduction by 2030; 90% by 2035; and 100% by 2040, compared to a baseline emission level. The baseline emission level is calculated for each provider by using average annual emissions associated with power generated and purchased for retail load for the years 2010 through 2012.

HB 2021 requires utilities to develop a CEP for meeting the reduction targets, concurrent with each IRP. In reviewing a CEP, the OPUC must ensure that utilities take actions as soon as practicable that facilitates rapid reduction of GHG emissions, demonstrate continual progress toward meeting the targets, and create a plan that is in the public interest. Further, the CEP must result in an affordable, reliable, and clean electric system. The law

does not require particular GHG percentage reductions be attained until 2030. The law contains affordability and reliability related provisions that can slow or pause compliance with the GHG targets, if implicated. The OPUC has a current open docket, UM 2273, in which provisions regarding the cost cap are being investigated.

A separate law adopted in 2009 requires retail electricity providers to report annually to the Oregon Department of Environmental Quality (ODEQ) the GHG emissions associated with electricity used to serve retail customers. The OPUC must use the data reported to the ODEQ to determine whether the GHG targets have been met.

RPS standards and related laws—In 2016, Oregon Senate Bill (SB) 1547 increased the 2007 benchmarks for the percentage of electricity that must come from renewable sources by dates certain and required the elimination of coal as a fuel for generation of electricity used to serve Oregon utility customers on or before January 1, 2030, although an exception in the law may extend this date five years for the output of Colstrip.

The Company has a 20% ownership share in Colstrip and has fully depreciated it as of December 31, 2025. Any capital spending after 2025 is expected to be fully depreciated within the year of spending. The forecasted annual revenue requirement for Colstrip, including depreciation, is updated annually in a separate, supplemental tariff and power cost related items are recovered annually under the AUT. In order to meet PGE's regulatory, legislative, and reliability requirements, the Company continues to evaluate its ongoing ownership in Colstrip. See Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" for information regarding legal matters related to Colstrip.

Any reduction in generation from Colstrip has the potential to provide additional capacity availability on the Colstrip transmission facilities, which stretch from eastern Montana to near the western end of that state to serve markets in the Pacific Northwest and neighboring states. PGE has an approximate 15% ownership interest in, and capacity on, the Colstrip transmission facilities. See *"Investing in a Clean Energy Future"* in this Overview for information regarding development in eastern Montana.

Other provisions of SB 1547:

- establish RPS thresholds of 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040, for the percentage of electricity that must come from renewable sources;
- limit the life of RECs generated from facilities that become operational after 2022 to five years, but continue unlimited lifespan for all existing RECs and allow for the generation of additional unlimited RECs for a period of five years for projects online before December 31, 2022; and
- provide opportunity to pursue recovery of energy storage costs related to renewable energy in the Company's RAC filings.

PGE believes it met the RPS threshold for 2025 and is on track to meet the threshold during 2026. The Company plans to submit its RPS report for 2025 by June 1, 2026. For a more comprehensive review of Environmental Matters, see "Environmental Matters" in Item 1.—Business.

HB 3179—In response to increasing utility bills and concerns about affordability, the Oregon Legislature in 2025 passed HB 3179. Under the provisions of the legislation, which will require a significant amount of rulemaking to implement, the OPUC shall balance the interests of the utility investor and the consumer by considering the cumulative economic impact of the proposed price or schedule of prices on the electric or natural gas company's residential customers. Electric or natural gas companies are required to file a multiyear rate plan on a regular interval that is no less than three and no more than seven years long. The OPUC shall require each electric and natural gas company to, at least annually, file with the OPUC, and make publicly available, a report on any price adjustments that the electric or natural gas company expects within the next twelve months. Such report, the first of which would be due at the end of 2026 at the earliest, must identify all price adjustment requests that an electric or natural gas company has filed or reasonably knows or anticipates to file. Any increase in residential prices may not take effect from November 1 to March 31.

EPA Regulations for Electric Generating Facilities—In April, 2024, the United States Environmental Protection Agency (EPA) released final regulations pertaining to electric generation facilities. The regulations included:

- •GHG regulations for new natural gas-based turbines and existing coal-based units, pursuant to section 111 of the Clean Air Act (CAA);
- •Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (the ELG Rule), which applies to wastewater discharges from coal-based generating units and establishes pollution control requirements, building upon the 2015 and 2020 ELG Rules; and
- •Updated Mercury and Air Toxics Standards (MATS), pursuant to section 112 of the CAA, which sets emissions limits for filterable particulate matter for coal-based generating units. The rule reduces those limits from the standards that were originally set in 2012.

On April 8, 2025, the President issued a proclamation, *Regulatory Relief for Certain Stationary Sources to Promote American Energy*, granting a two-year compliance exemption pursuant to the CAA Section 112(i)(4) for the EPA's MATS rule. The EPA subsequently notified companies whether their sources had been granted the exemption. Colstrip was granted an exemption until July 8, 2029. Environmental groups have filed court challenges to the MATS exemptions.

On June 11, 2025, to advance the goals of the President's Unleashing American Energy executive order, the EPA proposed to repeal the 2024 GHG emissions standards for fossil fuel-fired power plants promulgated under Section 111 of the CAA. The EPA also proposed to repeal specific amendments to the updated MATS, that were promulgated in 2024, including the revised filterable particulate matter emissions standard. Additionally, on June 30, 2025, the EPA proposed to update the 2024 ELG Rule to extend compliance deadlines and explore flexibilities to promote reliable and affordable power generation. On February 12, 2026, the EPA revoked the 2009 endangerment finding, thus removing the EPA's authority to regulate GHGs.

PGE continues to evaluate each of these rules to assess the impact it may have on the Company's continuing investment in Colstrip, which could be material. Compliance with the 2024 rules could require material upgrades at Colstrip with proposed compliance dates that may not be achievable or require the use of unproven technology, resulting in significant impacts to costs related to Colstrip. If upheld, or not modified by the EPA, the 2024 MATS and GHG Rules would require compliance as early as 2027 and 2032, respectively.

In addition to the EPA's proposed rulemakings, several legal challenges have been filed regarding these rules. In challenges to all three rules, at the EPA's request, the courts have granted stays to allow new EPA leadership to reevaluate the rule. These challenges, or attempts by the federal government to withdraw or modify the regulations, if successful, could affect the applicability to PGE and Colstrip, specifically. Given the uncertainty surrounding applicability of these laws and regulations, PGE cannot reasonably estimate the impact to its results of operations, financial position, and cash flows, however, if the MATS Rule and GHG Rule are ultimately enforced, it could require material additional compliance costs. To the extent these regulations result in increased compliance costs, the Company expects to seek recovery of those costs through the ratemaking process.

Regulatory Matters

PGE focuses on providing reliable, clean power to customers at affordable prices while providing a fair return to investors. To achieve this goal the Company must execute effectively within its regulatory framework and maintain prudent management of key financial, regulatory, and environmental matters that may affect customer prices and investor returns. The following discussion provides detail on such matters.

Corporate structure— On July 25, 2025, the Company submitted a formal application to the OPUC seeking approval of a holding company reorganization. PGE believes it to be in the best interests of its customers and shareholders to update its corporate structure into a holding company structure. The structure currently contemplated involves placing a non-operating corporate entity over the Company's existing structure.

Additionally, this structure would allow for the formation of a subsidiary of the holding company that could hold existing and future transmission assets. The intent of the reorganization is to take advantage of the financial flexibility provided by a holding company structure, and to support construction of new transmission assets, reliability planning, and economic development.

The application is one of many steps required to complete the reorganization, which needs OPUC approval under Oregon law as well as any necessary FERC approvals. Later in the process, PGE's Board of Directors will decide whether to submit the proposed reorganization to PGE shareholders for approval. Following completion of these steps and the receipt of all required approvals, each outstanding share of PGE common stock would automatically convert into a share of the new holding company (HoldCo) common stock on a one-for-one basis. PGE shareholders, immediately prior to consummation of the reorganization would own the same relative percentages of HoldCo following consummation of the reorganization. After the reorganization, PGE would be a wholly owned subsidiary of HoldCo, which would be an Oregon corporation.

As of the date of this filing, the OPUC proceeding remains in the evidentiary phase. Written testimony has been submitted, and the OPUC is continuing to compile additional filings and public input. No final order has been issued, and the proceeding remains active.

Declared states of emergency—The OPUC has approved a pre-authorized deferral of costs associated with qualifying declared states of emergency, which would include federal or state declared emergencies with impacts on PGE's service territory. Under this mechanism, PGE could provide notice of an event that qualifies within 30 days of the declared state of emergency and would not need to seek OPUC approval to apply deferred accounting treatment for incremental costs related to the emergency. The OPUC maintains responsibility to review utility requests to amortize deferred amounts in customer prices, including, among other requirements, a review of utility prudence and application of an earnings test, in a future proceeding.

In January 2024, the Company's service territory encountered a severe winter weather event that included snow, ice, and high winds over several days that caused catastrophic damage to physical assets and resulted in widespread customer power outages. As a result of the historic winter storm, Oregon's Governor declared a state of emergency on January 18, 2024, which allows PGE to seek recovery of incremental storm expenses through the previously filed emergency deferral. On February 9, 2024, PGE filed a Notice of Deferral with the OPUC under Docket UM 2190 for emergency restoration costs related to the January storm. As of December 31, 2025, PGE had deferred $48 million, including interest, as a regulatory asset for costs associated with repairing damage to transmission and distribution systems and restoring power to customers.

PGE believes that the deferral is probable of recovery and submitted a request for recovery early in the third quarter of 2025, with price changes to be effective over a two-year period beginning April 1, 2026. The OPUC has adopted a procedural schedule in Docket UE 458 for the regulatory review process that expects an order in March 2026. The OPUC has significant discretion in making the final determination of recovery based on its assessment of prudency and interpretation of the earnings test application, either of which could result in all, or a portion of, the deferral being disallowed. As of December 31, 2024, PGE's regulated return on equity, based on actual results, did not exceed the authorized rate of return as set by the OPUC, therefore, there has been no adjustment pursuant to the earnings test.

Any disallowance would be a charge to earnings, which could be material to the Company's financial condition, results of operations, or cash flows. For further information, see "*January 2024 storm and damage*" in Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

RCE—Under the RCE mechanism, originally authorized by the OPUC to be effective through 2025, PGE is allowed to pursue recovery of 80% of costs for RCEs above amounts forecasted in the Company's AUT, without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. As of December 31, 2025, PGE's deferred balance related to RCEs was $90 million, which includes $88 million related to RCEs in 2024 and $2 million in 2025. PGE filed the results of the 2024 PCAM

with the OPUC on July 1, 2025, in Docket UE 457, which included a request for $86 million, before considering interest, in RCE costs incurred in 2024, initiating a regulatory review process. Included in the filing, the Company requested an extension of the RCE mechanism for one year, through 2026. The OPUC has adopted a procedural schedule for the regulatory review process that expects an order in March 2026. Any resulting refund or collection impacting customer prices is expected to be effective April 1, 2026. PGE believes the deferred amounts as of December 31, 2025 are probable of recovery. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

Power costs—Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC, the 2025 AUT included a final increase in power costs for 2025, and a corresponding increase in annual revenue requirement of $72 million from 2024 levels, which were reflected in customer prices effective January 1, 2025. The 2026 AUT contains a $39 million increase in NVPC and has been included in customer prices beginning January 1, 2026. For more information regarding the PCAM, see "*Power operations*" within this Overview section of Item 7.

Renewable recovery framework—As previously authorized by the OPUC, the RAC is a primary method available to recover costs associated with renewable resources and the inclusion of prudent costs of energy storage projects associated with renewables, under certain conditions. The RAC allows PGE to recover prudently incurred costs of renewable resources through filings made each year, outside of a General Rate Case (GRC). In 2023, the Company filed for Clearwater, which went into service in January 2024. PGE did not submit a request for recovery of any renewable resources under the RAC during 2024 or 2025.

Under the RAC, during 2023, the Company submitted a filing in OPUC Docket UE 427 for Clearwater proposing to defer the revenue requirement, net of NVPC benefits, from the in-service date of January 2024 until Clearwater was reflected in customer prices, which was March 1, 2025. For the year ended December 31, 2024, PGE deferred the revenue requirement, net of NVPC benefits resulting in a net regulatory liability of $40 million, which began amortizing as a refund to customers on March 1, 2025 over a twelve month period, as approved by the OPUC in Order 25-075 issued February 21, 2025.

Order 25-075 also adopted conditions to be applied to the AUT and clarification of the applicability of those conditions were subsequently provided by the OPUC in Order 25-223, which granted certain of PGE's requests and denied others. PGE and NewSun Energy LLC, as an intervenor, both have Petitions for Judicial Review of Order 25-075 pending at the Oregon Court of Appeals. For the period of January 1, 2025 through December 31, 2025, PGE deferred an additional net $13 million regulatory liability, which remains subject to a future regulatory review, representing the deferred revenue requirement that the Company believes is probable of recovery, net of NVPC that is probable of refund to customers under the RAC for that period. The OPUC has significant discretion on overall prudence and in making the final determination of recovery or refund. Any cost disallowance or increased refunds would be recognized as a charge to earnings.

Seaside Grid BESS recovery—On May 30, 2025, PGE submitted a request to the OPUC to recover the revenue requirement associated with the Seaside Battery Energy Storage System (Seaside). The regulatory filing was pursuant to the expedited cost-recovery option introduced by the OPUC in its Order issued December 20, 2024 related to PGE's 2025 GRC (OPUC Docket UE 435).

On October 21, 2025, the OPUC issued an Order (Order 25-417) that was supported by a memorandum of understanding (MOU) entered into between PGE and key regulatory stakeholders. The MOU guided the recovery proceeding for Seaside, PGE's largest standalone battery storage project which has been serving customers since July 2025.

The Order calls for the following:

- a rate base increase of $220 million, net of estimated ITC benefits of $125 million;
- a 9.34% return on equity; and

- an annual revenue requirement increase of $42 million, excluding impacts related to NVPC, compared to PGE's filed request of $46 million at closing briefs.

The Order also resulted in a $6 million revenue requirement increase for the remainder of 2025, inclusive of NVPC customer benefits. Seaside's NVPC is included in PGE's AUT filings for 2026 (OPUC docket UE 452) and onward.

Other key items in the Order include the adoption of an earnings test for the twelve-month period ended October 31, 2026 at PGE's authorized ROE, implemented via a deferral to track Seaside revenues and refund excess earnings, if applicable. The Company has contested the applicability of an earnings test and in addition has not accrued any refunds, as it currently does not forecast to over earn for the period covered by the test.

The Seaside revenue requirement was included in customer prices effective October 31, 2025.

Distribution System Plan recovery mechanism—On December 23, 2025, PGE and certain intervening parties submitted a stipulation to the OPUC reflecting an agreement that resolves all issues, with the exception of the application of an earnings test as proposed by intervening parties, in PGE's request for recovery in UE 459 related to the Company's DSP Alternative Recovery Mechanism (ARM). The settlement and submitted stipulation were supported by an MOU entered into between PGE and key regulatory stakeholders. The MOU limited the scope of the ARM to specific capital investments included in the DSP docket (UM 2362) filed in December 2024, which enable network modernization, reliable customer service, and integration of clean energy and distributed energy resources.

Primary components of the stipulation include:

- A rate base increase of $218 million;
- 9.34% ROE per the MOU reflecting PGE's latest rate case;
- An annual revenue requirement increase of $57 million, compared to PGE's filed request of $72 million.

Of the $15 million of revenue requirement adjustments, approximately 87% are temporary in nature, allowing PGE to seek recovery of associated investments as applicable in its next GRC. These adjustments are driven primarily by non-distribution investments and are not attributable to specific assets. Per the previously noted MOU reached with stakeholders, the earliest possible rate effective date of PGE's next GRC would be May 1, 2027.

The terms of the stipulation remain subject to OPUC approval. The OPUC has adopted a procedural schedule for the regulatory review process in Docket UE 459 that anticipates an order in March 2026, with customer prices effective April 1, 2026. PGE cannot predict the ultimate outcome of the regulatory process.

Portland Harbor Environmental Remediation Account (PHERA) mechanism—The EPA has listed PGE as one of over one hundred Potentially Responsible Parties (PRPs) related to the remediation of the Portland Harbor Superfund site. As of December 31, 2025, significant uncertainties still remained concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. In a Record of Decision (ROD) issued in 2017, the EPA outlined its selected remediation plan for clean-up of the Portland Harbor site, which had an estimated total cost of $1.7 billion. Stakeholders have raised concerns that EPA's cost estimates are understated, and PGE estimates undiscounted total remediation costs for Portland Harbor per the ROD could range from $1.9 billion to $3.5 billion. The Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor. However, the Company may obtain sufficient information, prior to the final determination of allocation percentages among PRPs, to develop a reasonable estimate, or range, of its potential liability that would require recording an estimate, or low end of the range. The Company's liability

related to the cost of remediating Portland Harbor could be material to PGE's financial position. The impact of such costs to the Company's results of operations is mitigated by the PHERA mechanism. As approved by the OPUC, the recovery mechanism allows the Company to defer and recover estimated liabilities and incurred legal and technical analysis expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, including, but not limited to, insurance recoveries, and customer prices, as necessary. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds, and annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. PGE's results of operations may be impacted to the extent such expenditures were to be deemed imprudent by the OPUC or disallowed per the prescribed earnings test. PGE received settlement proceeds related to Portland Harbor Superfund insurance coverage settlement agreements during 2025, which were deferred into the PHERA mechanism. PGE is continuing insurance recovery activity with additional insurers. For further information regarding the PHERA mechanism, see *"EPA Investigation of Portland Harbor"* in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

New Large Load—In December 2023, the OPUC established Docket UE 430 to investigate new load connection costs. Following a lengthy regulatory process, in December 2024, PGE filed Advice No. 24-38 with the OPUC. This filing introduced several proposed changes to PGE policies and tariffs that, if approved, would: i) reasonably protect other customers from the cost to connect new large load customers; ii) improve transmission system planning and capacity; iii) provide fair recovery of distribution investment costs from large load users; and iv) implement contractual requirements designed to appropriately allocate and recover distribution and transmission costs and mitigate the risk of stranded assets, while providing flexibility to meet large customer needs.

On April 15, 2025, the OPUC approved PGE's filing, as revised, with an effective date of April 16, 2025, on condition that the issues raised in the filing would continue to be evaluated in a new Commission docket, UM 2377. This initial approval allowed PGE to begin working with large load customers to form a load interconnection queue, conduct studies to assess and allocate connection costs, and offer study and service agreements. Applicable agreements with new large load customers may be revised and updated based on the outcome in the separate OPUC proceeding, UM 2377, that was opened to address PGE's proposed tariff changes and related issues.

In June 2025, the Oregon Legislature passed HB 3546 relating to service to large data centers. HB 3546, which became effective in June 2025, directs the OPUC to provide a classification for retail customers deemed large energy use data center facilities. Any tariffs for the class must allocate costs to the class in a manner that is equal or proportional to the costs of serving the class, or directly assign the costs to large energy use data center facilities and avoid unwarranted shifting of costs to other classes. HB 3546 also directs the OPUC to require that electric companies serving data centers must enter into a contract for services with such customer under terms and conditions specified by the law. The OPUC has included HB 3546 alignment and establishment of a data center classification for retail customers within the scope of UM 2377 as well as other topics that may apply to all large load customers. The OPUC is expected to issue an Order in UM 2377 in the second quarter of 2026.

Operating Activities

In addition to providing electricity from PGE's own generation portfolio, to meet retail load requirements and balance energy supply with customer demand, manage risk, and administer its long-term wholesale contracts, the Company purchases and sells electricity in the wholesale market. To fuel its generation portfolio, the Company purchases natural gas in the United States and Canada and sells excess gas back into the wholesale market. PGE also performs portfolio management and wholesale market sales services for third parties in the region and purchases and sells environmental credits bundled with electricity in the wholesale marketplace.

PGE participates in the western EIM, which enables, among other benefits, greater integration of renewable energy onto the grid by better balancing the variable output of renewable resources.

The Company signed an implementation agreement and filed tariff changes with the FERC to join the EDAM, which is expected to build on the success of the western EIM and help provide PGE and its customers additional

access to affordable, reliable, and clean energy. In August 2025, the FERC approved PGE's revisions to its Open Access Transmission Tariff for EDAM participation. In September 2025, the California Legislature approved Assembly Bill 825 (the Pathways Bill), authorizing the CAISO to transition market governance, including the EDAM, to an independent regional organization.

The EDAM, anticipated to begin operation in 2026, will allow market participants to submit bids for their forecasted energy demand and available generation resources a day ahead of expected use. The EDAM will then optimize transmission and resource use across all market participants, enabling access to the lowest cost resources to meet regional needs. The EDAM is expected to leverage PGE's existing technology and systems and utilize the Company's transmission system to connect regional resources, such as hydropower and wind facilities in the Pacific Northwest and solar facilities in California and the desert Southwest, across a unified market platform.

As part of its ongoing commitment to reliably serving both retail and wholesale customers, PGE is evaluating alternatives to participation as a financially binding entity in the Western Power Pool's resource adequacy program known as the Western Resource Adequacy Program (WRAP). While PGE continues to support the regional planning and analytical framework established by the WRAP, the Company provided notice of withdrawal in October 2025. PGE is in collaboration with utilities committed to the EDAM and Oregon regulated load serving entities to develop and adopt a resource adequacy framework that enhances reliability, is aligned more closely with the EDAM design, and reflects the operational realities of a rapidly evolving electric grid across the western United States, with a target operational date of 2028.

PGE generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers. The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Summer peak deliveries have continued to exceed those of the winter months for nearly ten years, generally resulting from growing air conditioning demand and the trend toward a warmer overall climate. In August 2023, demand reached a new all-time high, surpassing the previous mark, which was set in summer 2021. Historically, PGE had experienced its highest average megawatt deliveries and retail energy sales during the winter heating season and recorded its current winter peak load in December 2022. Summer peak deliveries in each year since 2021 have exceeded that winter peak. For further information regarding seasonal fluctuations, see *"Seasonality"* in the Customers and Revenues section in Item 1.—"Business."

Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues. Wholesale power availability and price, hydro and wind generation, and fuel costs for thermal plants can also affect income from operations. PGE has taken measures to enhance the availability of supply chain-constrained items that are needed to serve new and existing customers, such as securing inventory of critical materials to improve reliability, reserving manufacturing capacity with strategic partners, and evaluating availability with established and new suppliers. The Company's materials and supplies forecasting process is designed to secure materials availability as well as help mitigate cost increases through long-term agreements, supplier engagement, and expanding the supply base. PGE is monitoring the fluid situation around tariffs and trade policies and continues to evaluate any potential impact to its operations and the need to implement applicable mitigation strategies.

Customers and demand—The following tables present total energy deliveries and the average number of retail customers by type for 2025 and 2024.

Energy deliveries (MWh in thousands)	2025	2024	% Change	% Change (Weather-Adjusted)
Retail:				
Residential	7,596	7,732	(1.8)%	0.4%
Commercial	6,467	6,509	(0.6)	(0.2)
Industrial	5,905	5,032	17.3	17.4
Subtotal	19,968	19,273	3.6	4.6
Direct access:				
Commercial	548	515	6.4	6.4
Industrial	2,014	1,909	5.5	5.5
Subtotal	2,562	2,424	5.7	5.7
Total retail energy deliveries	22,530	21,697	3.8	4.7
Wholesale energy deliveries	9,392	9,722	(3.4)	
Total energy deliveries	31,922	31,419	1.6	

Average number of retail customers	2025		2024		% Increase/ (Decrease)
Residential	840,457	88%	829,721	88%	1.3%
Commercial	114,277	12	113,518	12	0.7
Industrial	218	—	208	—	4.8
Direct access	703	—	497	—	41.4
Total	955,655	100%	943,944	100%	1.2

In 2025, retail energy deliveries increased 3.8% from 2024, with increases in demand from industrial customers outweighing the decreases seen in the residential and commercial classes. The industrial class has experienced an increase in energy deliveries, due primarily to continued growth in the high-tech and digital services sectors. Compared to the prior year, weather served to reduce deliveries, as temperatures were overall mild. Temperatures in the fourth quarter were mild, with December experiencing the warmest average temperature on record at the Portland International Airport.

Residential energy deliveries, which are most sensitive to fluctuations in temperatures, were 1.8% lower in 2025 than 2024, due to a 3% decrease in average usage per customer, which resulted largely from mild temperatures, and was partially offset by a 1.3% increase in the average number of customers. PGE has seen the number of rooftop solar installations increase in its service territory over the past few years, which continues to reduce the average usage per customer.

Commercial energy deliveries decreased 0.1% from the prior year driven by mild temperatures in 2025, impacts of programmatic energy efficiency and uncertainty in economic conditions that tempered commercial growth in 2024 and have continued into 2025.

Industrial energy deliveries increased 14.1% in 2025 due to continued strength in the digital service sector. Several large customers experienced continued growth in 2025 and new data center facilities came online.

Total heating degree-days, an indication of electricity use for heating, declined 3% in 2025 from 2024 in total, and were 11% below the 15-year moving average. In 2025, heating degree-days were lower in each quarter of the year, except for the first quarter, which was only slightly higher. The fourth quarter, which is normally a high heating demand period, in 2025, was even milder than 2024, which was among the warmest ever recorded to that point. Correspondingly, cooling degree-days, a similar indication of the extent to which customers were likely to have used electricity for cooling, exceeded the 15-year average by 9%, although were 8% below the 2024 total, which was 18% above average, illustrating that the two most recent summer seasons have continued to see warm temperatures when compared to historical averages.

The following table presents the number of heating and cooling degree-days in 2025 and 2024, along with the current 15-year averages, reflecting the influence that weather had on comparative energy deliveries.

	Heating Degree-Days			Cooling Degree-Days		
	2025	2024	15-Year Average	2025	2024	15-Year Average
1st quarter	1,772	1,755	1,819	4	—	—
2nd quarter	464	547	606	102	108	109
3rd quarter	19	36	60	588	643	521
4th quarter	1,294	1,324	1,502	—	—	6
Total	3,549	3,662	3,987	694	751	636
Increase (decrease) from the 15-year average	(11)%	(8)%		9%	18%	

Customers are measured and reported in terms of individual service points, with certain companies, which are classified among the commercial, industrial, or Direct Access categories, having multiple service points. ESSs supplied Direct Access customers with energy representing 11% of PGE's total retail energy deliveries during both 2025 and 2024. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 12% of the Company's total retail energy deliveries for 2025. With the adoption of the New Large Load Direct Access program in 2020, as much as 16% of the Company's 2025 energy deliveries could have been supplied by ESSs. The OPUC, under docket UM 2024, has undertaken an investigation of long-term Direct Access with program caps being one of the issues under consideration. This regulatory proceeding is expected to conclude in early 2026.

Power operations—PGE utilizes a combination of its own generating and energy storage resources and wholesale market transactions to meet the energy needs of, and obtain reasonably-priced power for, its retail customers, manage risk, and administer its long-term wholesale contracts. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. PGE also purchases wholesale natural gas in the United States and Canada to fuel its generating portfolio and sells excess gas back into the wholesale market. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period and impacts NVPC and income from operations.

The following table provides information regarding the performance of the Company's generation portfolio.

	Plant availability [1]		Actual energy provided compared to projected levels [2]		Actual energy provided as a percentage of total retail load	
	2025	2024	2025	2024	2025	2024
Thermal:						
Natural gas	87%	82%	102%	98%	37%	36%
Coal [3]	79	78	97	93	6	6
Wind [4]	89	92	96	101	9	10
Hydro	85	93	99	96	4	4

(1)Plant availability represents the percentage of the year plants were available for operations, which is impacted by planned maintenance and forced, or unplanned, outages.
(2)Projected levels of energy are included as part of PGE's AUT. Such projections establish the power cost component of retail prices for the following calendar year. Any shortfall is generally replaced with power from higher cost sources, while any excess generally displaces power from higher cost sources.
(3)Plant availability reflects Colstrip, which PGE does not operate.
(4)Plant availability includes Wheatridge Renewable Energy Facility and Clearwater, which PGE does not operate.

Energy received from PGE-owned and jointly-owned thermal plants in 2025 compared to 2024 increased by 4%. This increase is primarily driven by economic dispatch decisions. Energy expected to be received from thermal resources is projected annually in the AUT based on forecast market prices, variable costs to run the plant, and the constraints of the plant. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year.

Total energy received from all hydroelectric sources, both PGE-owned generation and purchased, increased 8% in 2025 compared to 2024 primarily due to more favorable hydro conditions in the current period. Energy purchased from mid-Columbia and other regional hydroelectric projects increased 10% while energy generated by the Company-owned facilities decreased 5% in 2025. Energy expected to be received from hydroelectric resources in 2025 was projected in the AUT based on a modified hydro study, which utilizes 10 years of historical stream flow data. For further detail on regional hydro results, see "Purchased power and fuel" in the Results of Operations section in this Item 7.

Energy received from PGE-owned wind resources and under contracts decreased 9% in 2025 compared to 2024. Energy expected to be received from wind generating resources is projected annually in the AUT based on historical generation. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available.

Under the PCAM, PGE may share with customers a portion of cost variances associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC, which is reset annually by means of the AUT filings) and actual NVPC for the year, if such differences exceed a prescribed "deadband" limit, which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2025 and 2024:

- For 2025, actual NVPC was below baseline NVPC by $6 million, which was within the established deadband range. Accordingly, there is no estimated refund to customers under the PCAM for 2025. A

final determination regarding the 2025 PCAM results will be made by the OPUC through a public filing and review in 2026.

•For 2024, actual NVPC was below baseline NVPC by $78 million, which was outside the established deadband range. Pursuant to the PCAM and related earnings test, because PGE's preliminary regulatory ROE was below 10.5%, there was no estimated refund to customers under the PCAM for 2024.

As approved by the OPUC in PGE's 2024 GRC, the RCE mechanism allows PGE to pursue recovery of 80% of costs for RCEs above amounts forecasted in the Company's AUT, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. For more on the RCE, see Note 7, Regulatory Assets and Liabilities in the Notes to Condensed Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Business transformation and optimization expenses—In 2025, PGE incurred $42 million incremental business transformation and optimization expenses, which include strategic advisory and workforce realignment expenses, focused on a multi-year cost management initiative to realize long-term benefits. For more information on the impact of these costs on annual results, see "Generation, transmission and distribution," "Administrative and other," "Depreciation and amortization," and "Other income, net" in the Results of Operations section of this Overview. The Company expects to incur business transformation and optimization expenses related to these initiatives throughout 2026.

Additionally, PGE has incurred incremental accounting, legal, and consulting costs related to its submission of a regulatory application for approval of a holding company reorganization. For more on the corporate structure see *"Corporate Structure"* in the Regulatory Matters section of this Overview.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The results of operations are as follows for the years presented (dollars in millions):

	Years Ended December 31, 2025 Amount	2024 Amount	% Increase (Decrease)
Total revenues	$ 3,576	$ 3,440	4%
Operating expenses:			
Purchased power and fuel	1,411	1,418	—
Generation, transmission and distribution	450	436	3
Administrative and other	392	403	(3)
Depreciation and amortization	578	496	17
Taxes other than income taxes	190	175	9
Total operating expenses	3,021	2,928	3
Income from operations	555	512	8
Interest expense, net *	232	211	10
Other income:			
Allowance for equity funds used during construction	18	23	(22)
Miscellaneous income, net	18	26	(31)
Other income, net	36	49	(27)
Income before income taxes	359	350	3
Income tax expense	53	37	43
Net income	$ 306	$ 313	(2)%

* Includes an allowance for borrowed funds used during construction of $11 million in 2025 and $15 million in 2024.

2025 Compared to 2024

Net income for 2025 decreased $7 million from 2024. Retail revenues increased primarily due to price changes to cover anticipated higher NVPC and general cost increases, as authorized by the OPUC. Wholesale revenues have decreased, driven by a decline in the average price of wholesale deliveries, although lower sales volumes also contributed to the decline. Purchased power and fuel expense declined slightly, reflecting stable market conditions and lower commodity prices. Generation, transmission and distribution expenses were up slightly, while total Administrative and other expenses were reduced 3% from 2024. Increases in Depreciation and amortization expense, driven by higher depreciable asset balances, and Interest expense, net, due to higher long-term debt balances, were largely anticipated and somewhat offset in net income by increased revenues. Income tax expense was up due primarily to lower PTC benefits.

Total revenues consist of the following for the years presented (in millions):

	2025	2024	% Increase (Decrease)
Retail:			
Residential	$ 1,486	$ 1,457	2%
Commercial	969	914	6
Industrial	536	435	23
Subtotal	2,991	2,806	7
Direct Access:			
Commercial	16	10	60
Industrial	25	23	9
Subtotal	41	33	24
Subtotal Retail	3,032	2,839	7
Alternative revenue programs, net of amortization	21	(40)	(153)
Other accrued (deferred) revenues, net	17	16	6
Total retail revenues	3,070	2,815	9
Wholesale revenues	418	558	(25)
Other operating revenues	88	67	31
Total revenues	$ 3,576	$ 3,440	4%

Total retail revenues—The following items contributed to the increase in Total retail revenues for the year ended December 31, 2025 compared to the year ended December 31, 2024 (dollars in millions):

Year ended December 31, 2024	$ 2,815
Change in prices as a result of the AUT, approved by the OPUC (partially offset in Purchased power and fuel)	72
Retail energy deliveries driven by changes in customer demand	66
Change in average price of energy deliveries due primarily to changes in overall customer prices beyond the AUT, as approved by the OPUC	60
Clearwater RAC deferral (largely offset in Purchased power, Depreciation and amortization, and Income tax expense)	37
Wildfire mitigation, offset in operating expenses and amortization	23
Colstrip annual tariff update	16
Combination of various supplemental tariffs and adjustments	(19)
Year ended December 31, 2025	3,070
Change in Total retail revenues	$ 255

Wholesale revenues result primarily from sales of electricity and environmental credits to utilities and power marketers made in the Company's efforts to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2025, a $140 million, or 25%, decrease from 2024 in wholesale revenues occurred as a $90 million decrease resulted from lower average prices received when the Company sold power into the wholesale market. The decline in average sales prices resulted in large part to market volatility around specific regional weather events in January 2024 and milder overall weather in 2025. In addition, sales volumes decreased 3%, which resulted in a $19 million decrease, and the Company sold $32 million fewer environmental credits in 2025 than in the prior year.

Other operating revenues increased $21 million, or 31%, in 2025 from 2024, with the largest contributors being an increase from imbalance transactions with ESS providers, which is offset in Purchased power and fuel expense, and additional joint pole revenues.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts.

The following items contributed to the change in Purchased power and fuel for the year ended December 31, 2025 compared to the year ended December 31, 2024 (dollars in millions):

Year ended December 31, 2024	$	1,418
Average variable power cost per MWh		(109)
Total system load		27
2021 PCAM deferral amortization		(15)
RCE deferral activity, net		90
Year ended December 31, 2025		1,411
Change in Purchased power and fuel	$	(7)

Average variable power cost per MWh (in dollars):		
Year ended December 31, 2024	$	49.08
Year ended December 31, 2025	$	45.63

Total system load (MWh in thousands):	
Year ended December 31, 2024	30,348
Year ended December 31, 2025	30,848

For the year ended December 31, 2025, the $109 million decrease related to the change in average variable power cost per MWh was primarily driven by an 11% decrease in the average cost for purchased power, offset by a 3% increase in the average cost for the Company's own generation. The $27 million increase related to total system load was comprised of a 2% increase in energy obtained from purchased power, and a 1% increase in energy obtained from PGE's own generation.

PGE's sources of energy, total system load, and retail load requirement for the years presented are as follows:

	Years Ended December 31, 2025		2024	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	11,424	37%	10,939	36%
Coal	1,936	6	1,910	6
Total thermal	13,360	43	12,849	42
Hydro	1,205	4	1,267	4
Wind	2,711	9	2,922	10
Total generation	17,276	56	17,038	56
Purchased power:				
Hydro	7,431	24	6,752	22
Wind	1,195	4	1,386	5
Solar	1,415	5	1,119	4
Natural Gas	885	3	94	—
Waste, Wood and Landfill Gas	107	—	170	1
Source not specified	2,539	8	3,789	12
Total purchased power	13,572	44	13,310	44
Total system load	30,848	100%	30,348	100%
Less: wholesale sales	(9,383)		(9,722)	
Retail load requirement	21,465		20,626	

Purchased power in the table above includes power received from QFs as follows:

	Years Ended December 31, 2025	2024
Sources of energy (MWhs in thousands):		
PURPA purchased power:		
Hydro	29	31
Wind	29	29
Solar	605	580
Waste, Wood, Landfill Gas, and Other	107	117
Total	770	757

The following table presents the forecasted April-to-September 2026 and actual April-to-September 2025 and 2024 runoff at particular points of major rivers relevant to PGE's hydro resources:

	Runoff as a Percent of Normal*		
Location	2026 Forecast	2025 Actual	2024 Actual
Columbia River at The Dalles, Oregon	94%	77%	74%
Mid-Columbia River at Grand Coulee, Washington	101	78	74
Clackamas River at Estacada, Oregon	76	69	91
Deschutes River at Moody, Oregon	90	93	93

* Volumetric water supply forecasts and historical averages for the Pacific Northwest region are prepared by the Northwest River Forecast Center, with the Natural Resources Conservation Service and other cooperating agencies.

Actual NVPC, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $133 million in 2025 compared with 2024. The increase attributable to changes in Purchased power and fuel expense was the result of a 7% decrease in the average variable power cost per MWh and a 2% increase in total system load. This was partially offset by an decrease in wholesale revenues driven by a 22% decrease in the volume of wholesale energy deliveries and a 3% lower average price per MWh sold.

The following items contributed to the increase in actual NVPC for the year ended December 31, 2025 compared to the year ended December 31, 2024 (in millions):

Year ended December 31, 2024	$	860
Purchased power and fuel expense		(82)
Wholesale revenues		140
2021 PCAM deferral amortization		(15)
RCE deferral activity, net		90
Year ended December 31, 2025		993
Change in NVPC	$	133

For further information regarding NVPC in relation to the PCAM, see *"Power operations"* in the Overview section of this Item 7.

Generation, transmission and distribution expense increased $14 million or 3% for the year ended December 31, 2025 compared to the year ended December 31, 2024, with the change attributed largely to the following items (in millions):

Year ended December 31, 2024	$	436
Vegetation management, inspection, wildfire mitigation, and distribution maintenance expenses		5
Generation facility maintenance expenses driven by major maintenance activities and decreased run hours		(15)
Service restoration and storm response costs		9
Business transformation and optimization expenses		5
Energy storage		4
Miscellaneous expenses		6
Year ended December 31, 2025		450
Change in Generation, transmission and distribution	$	14

In the table above, $(2) million related to vegetation management, $13 million related to wildfire mitigation, $9 million related to storm response costs and $5 million related to major maintenance have been offset through customer prices or specific regulatory mechanisms.

Administrative and other expense decreased $11 million, or 3%, for the year ended December 31, 2025 compared to the year ended December 31, 2024 due largely to the following items (in millions):

Year ended December 31, 2024	$	403
Employee compensation and benefits expenses		(4)
Regulatory and professional service costs		2
Customer related costs		(18)
Business transformation and optimization expenses		32
Amortization of COVID-19 bad debt expense deferral		(13)
Miscellaneous expenses		(10)
Year ended December 31, 2025		392
Change in Administrative and other	$	(11)

In the table above, $7 million of the decrease in customer related costs is due to regulatory programs that have been offset through customer prices or specific regulatory mechanisms.

Depreciation and amortization expense increased $82 million or 17% for the year ended December 31, 2025 compared to year ended December 31, 2024, with the change largely resulting from the following items (in millions):

Year ended December 31, 2024	$	496
Capital additions		69
Business transformation and optimization expenses		1
Activity related to regulatory programs (offset elsewhere on the income statement)		1
Right of use asset amortization expenses		11
Year ended December 31, 2025		578
Change in Depreciation and amortization	$	82

Taxes other than income taxes expense increased $15 million, or 9%, in 2025 compared with 2024, primarily due to higher franchise fees and property tax expenses slightly offset by lower payroll taxes.

Interest expense increased $21 million, or 10%, in 2025 compared with 2024 driven by higher average balances of outstanding debt.

Other income, net decreased $13 million, or 27%, in 2025 compared to 2024. The decrease was primarily attributable to lower AFUDC equity income driven by lower construction work-in progress balances and $4 million in business transformation and optimization expenses related to pension settlements.

Income tax expense increased $16 million, or 43%, in 2025 compared to 2024 primarily driven by decreased PTC benefits resulting from expiration of the 10-year PTC generation window at Tucannon near the end of 2024 and higher pre-tax income as compared to the prior year.

2024 Compared to 2023

For a comparison of the Company's results of operations for the fiscal year ended December 31, 2024 to the year ended December 31, 2023, see Item 7.—" Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2024, filed with the SEC on February 14, 2025.

Liquidity and Capital Resources

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of this Annual Report on Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan." in Item 1A.—"Risk Factors," for further information.

Capital Requirements

The following table presents actual capital expenditures and debt maturities for 2025 and projected capital expenditures and future debt maturities for 2026 through 2030 (in millions, excluding AFUDC):

	Years Ended December 31,					
	2025	2026	2027	2028	2029	2030
Ongoing capital expenditures [1]	$ 642	$ 865	$ 895	$ 925	$ 925	$ 925
Transmission	174	215	390	420	515	525
Clearwater	7	—	—	—	—	—
BESS projects	320	—	—	—	—	—
Hybrid projects	—	575	455	—	—	—
Total capital expenditures [2]	$ 1,143	$ 1,655	$ 1,740	$ 1,345	$ 1,440	$ 1,450
Long-term debt maturities	$ 170	$ —	$ 160	$ 100	$ 200	$ 325

(1)Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects. Includes accrued capital additions, preliminary engineering, removal costs, and certain intangible working capital assets.

(2)Amounts subsequent to 2025 are estimates as of the date of this report and may be affected by economic conditions, including but not limited to, impacts of inflation, changes to the cost of materials and labor, and financing costs.

During 2025, PGE funded its capital expenditures through a combination of cash from operations in the amount of $1.1 billion, proceeds from the issuance of FMBs in the total amount of $310 million, and net proceeds from the issuance of shares pursuant to the at-the-market offering program of $250 million. Capital expenditures in 2026 are expected to be approximately $1.7 billion. PGE plans to fund the 2026 capital expenditures with cash from operations during 2026, which is expected to range from $1 billion to $1.2 billion, the issuance of debt securities of up to $350 million, the issuance of equity securities of up to $300 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt, equity, and commercial paper will be dependent upon the timing and amount of capital expenditures and debt payments. For a discussion concerning PGE's ability to fund its future capital requirements, see "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for generation, transmission, distribution, and energy storage facilities to support both new and existing customers, along with information technology systems and debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The pending Acquisition to acquire PacifiCorp's Washington state regulated utility business will require financing of $1.9 billion. The acquisition is supported by a fully committed bridge facility with Barclays Bank PLC and JPMorgan Chase Bank, N.A. for $1.9 billion. The Company expects to permanently finance the transaction through a balanced mix of debt, equity, and its minority investment partner, Manulife Infrastructure Fund III L.P. ("Manulife") and its affiliates including John Hancock Life Insurance Company (USA). In connection with the financing plan, PGE expects equity commitments from Manulife to finance up to $600 million of the purchase. Assuming the closing of the transactions contemplated by the Agreement and the consummation of the financing transactions, Manulife will be the Company's joint venture partner in the business. PGE would remain majority owner and sole operator.

The Company believes its cash flow from operating activities, access to credit markets, and its credit facilities provide sufficient liquidity to support estimated future cash requirements, including the cash consideration necessary to close on the proposed Acquisition. For additional information on the proposed acquisition, see "Pending Acquisition" in the Overview section in this Item 7., and Note 21, Subsequent Events, in Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The following summarizes PGE's cash flows for the periods presented (in millions):

	Years Ended December 31, 2025	2024
Cash and cash equivalents, beginning of year	$ 12	$ 5
Net cash provided by (used in):		
Operating activities	1,118	778
Investing activities	(1,196)	(1,297)
Financing activities	142	526
Net change in cash and cash equivalents	64	7
Cash and cash equivalents, end of year	$ 76	$ 12

2025 Compared to 2024

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The following items contributed to the net change in cash flows from operations for 2025 compared to 2024 (dollars in millions):

	Increase/ (Decrease)
Net income	$ (7)
Accounts receivable and unbilled revenue	50
Margin deposit activity	58
Accounts payable	(3)
Regulatory deferral activity	149
Depreciation and amortization	82
Deferred income taxes	14
Tax credit sales	67
Alternative revenue programs	(61)
Other miscellaneous changes	(9)
Net change in cash flow from operations	$ 340

For additional information regarding changes in Net income, see the Results of Operations section in this Item 7.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that total depreciation and amortization in 2026 will range from $560 million to $580 million. Combined with all other sources, cash provided by operations in 2026 is estimated to range from $1 billion to $1.2 billion.

Cash provided by operations includes the recovery in customer prices of cash charges related to various long-term contractual obligations such as interest on long-term debt and purchased power and fuel contracts. PGE's anticipated employer contributions for its defined benefit pension plan and other postretirement plans is $26 million in 2026, $23 million in 2027, $20 million in 2028, $18 million in 2029, and $17 million in 2030. Contributions are expected to be covered by cash provided by operations. For additional information regarding

contractual obligations, see Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's generation, transmission, distribution, and energy storage facilities. The $101 million decrease in net cash used in investing activities in 2025 compared with 2024 is primarily due to capital expenditures related to BESS projects and other new construction and improvements to PGE's distribution, transmission, and generation facilities.

The Company plans for $1.7 billion of capital expenditures in 2026 related to upgrades to and replacement of generation, transmission, and distribution infrastructure as well as costs related to hybrid projects. PGE plans to fund the 2026 capital expenditures with cash from operations during 2026, as discussed above, as well as with the issuance of debt, issuances of shares pursuant to the at-the-market offering program, and short-term debt as necessary. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2025, cash provided by financing activities was primarily the result of the funding of $310 million in FMBs and $250 million in proceeds from the issuance of common stock pursuant to at-the-market offering programs. This was partially offset by payments of dividends in the amount of $225 million and $170 million of long-term debt.

2024 Compared to 2023

For a comparison of liquidity and capital resources and the Company's cash flow activities for the fiscal year ended December 31, 2024 and 2023, see Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2024, which was filed with the SEC on February 14, 2025.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	S&P
Issuer credit rating	A3	BBB+
Senior secured debt	A1	A
Commercial paper	P-2	A-2
Outlook	Stable	Stable

In December 2025, Moody's revised the Company's outlook from Negative back to Stable as a result of the Company's improved metrics, which are expected to remain above the downgrade threshold.

In the event Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to higher fees on its revolving credit facility. The Company could also be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheets, while any letters of credit issued are not reflected in the Company's consolidated balance sheets.

As of December 31, 2025, PGE had posted $239 million of collateral with these counterparties, consisting of $116 million in cash and $123 million in bank letters of credit. Based on the Company's energy portfolio,

estimates of energy market prices, and the level of collateral outstanding as of December 31, 2025, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $70 million and decreases to $54 million by December 31, 2026 and $3 million by December 31, 2027. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade as of December 31, 2025 is $168 million and decreases to $150 million by December 31, 2026 and $66 million by December 31, 2027.

On December 24, 2025, PGE executed an amendment to an existing enabling agreement with a counterparty that was holding $158 million of PGE collateral, consisting of $48 million in cash and $110 million in bank letters of credit. The amendment provided a cap of the amount required based on credit ratings. This resulted in the recall of $128 million of the posted collateral in January 2026, consisting of $48 million in cash and $80 million in bank letters of credit.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facilities would increase.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2025, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $785 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt to total capital ratio). As of December 31, 2025, the Company's debt to total capital ratio, as calculated under the credit agreements, was 53.0%.

Debt and Equity Financings

PGE's ability to secure sufficient short- and long-term capital at a reasonable cost is determined by its financial performance and outlook, credit ratings, capital expenditure requirements, alternatives available to investors, market conditions, and other factors, such as the volatility in the capital markets in response to inflationary pressures and interest rate increases by the federal reserve. Management believes that the availability of its revolving credit facility, the expected ability to issue short- and long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

Short-term Debt—Pursuant to an order issued by the FERC on January 12, 2026, PGE has authorization to issue short-term debt up to a total of $900 million through February 6, 2028. The following table shows available liquidity as of December 31, 2025 (in millions):

	December 31, 2025		
	Capacity	Outstanding	Available
Revolving credit facility [1]	$ 750	$ —	$ 750
Letters of credit [2]	320	192	128
Total credit	$ 1,070	$ 192	878
Cash and cash equivalents			76
Total liquidity			$ 954

(1)Scheduled to expire in September 2030, PGE has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay outstanding commercial paper. As of December 31, 2025, PGE had no commercial paper outstanding, therefore, the elected available credit capacity is $750 million.

(2)PGE has four letter of credit facilities under which the Company can request letters of credit for an original term not to exceed one year.

As of December 31, 2025, PGE had a $750 million unsecured revolving credit facility scheduled to expire in September 2030. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% of the facility approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and to provide cash for general corporate purposes. PGE may borrow for one, three or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2025, PGE had no commercial paper outstanding.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2025, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2025, the aggregate unused available credit capacity under the revolving credit facility was $750 million.

In addition, PGE has four letter of credit facilities under which the Company has total capacity of $320 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, which are considered off-balance sheet arrangements, letters of credit for a total of $192 million were outstanding as of December 31, 2025. PGE works to optimize its use of its letter of credit facility to manage energy trading margin.

Long-term Debt—During 2025, PGE issued and funded a total of $310 million of Long-term Debt and repaid a total of $170 million.

On March 25, 2025, PGE entered into a Bond Purchase Agreement related to the sale of $310 million in FMBs. The Bonds were issued and funded in full on March 25, 2025 and consist of:

- a series, due in 2035, in the amount of $60 million that will bear interest from its issuance date at an annual rate of 5.36%;
- a series, due in 2045, in the amount of $50 million that will bear interest from its issuance date at an annual rate of 5.72%; and
- a series, due in 2055, in the amount of $200 million that will bear interest from its issuance date at an annual rate of 5.84%.

On November 14, 2024, PGE obtained a 366-day term loan from lenders in the aggregate principal of $300 million under a 366-Day Bridge Credit Agreement. Pursuant to the Agreement, on November 14, 2024, PGE drew a loan from the Lenders in the aggregate principal of $220 million. The term loan bore interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 80.0 basis points. The interest rate was subject to adjustment pursuant to the terms of the loan. On December 31, 2024, PGE repaid $50 million of the term loan, leaving an outstanding balance of $170 million. On March 31, 2025, the Company repaid another $102 million, and on October 27, 2025 repaid the remaining balance of $68 million, repaying the loan in full.

As of December 31, 2025, total long-term debt outstanding, net of $17 million of unamortized debt expense, was $4,662 million, none of which is scheduled to mature in 2026.

Equity—In July 2024, PGE entered into an equity distribution agreement under which it could sell up to $400 million of its common stock through at-the-market offering programs. The Company entered into forward sale agreements for 5,756,432 shares and 1,420,049 shares in 2025 and 2024, respectively. In 2024, the Company issued 1,066,549 shares pursuant to the forward sale agreements and received net proceeds of $50 million. During 2025, the Company issued 5,919,618 shares pursuant to the forward sale agreements and received net proceeds of $250 million. The Company could have physically settled the remaining amount by delivering 190,314 shares in exchange for cash of $8 million as of December 31, 2025. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

PGE anticipates entering into a new at-the-market offering program in the first quarter of 2026. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

For additional information on the at-the-market offering program, see Note 13, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Capital Structure—PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities and excluding lease obligations) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company's common equity ratio was 47.0% and 45.6% as of December 31, 2025 and 2024, respectively.

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE applies regulatory accounting, which includes the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators, prices are designed to recover the specific enterprise's cost-of-service, and, in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets is not probable, PGE would expense such items in the period such determination is made. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

For additional information on PGE's regulatory assets and liabilities, see "*Regulatory Matters*" in the Overview section in this Item 7., and Note 7, Regulatory Assets and Liabilities in Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Asset Retirement Obligations

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Estimates for ARO liabilities are generally based on site-specific studies and are periodically subject to updates and changes that may arise over time.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. For revisions to ARO liabilities in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Accretion of the ARO liability is classified as Depreciation and amortization expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

As a co-owner of Colstrip, PGE has provided surety bonds, which are considered off-balance sheet arrangements, of $18 million as of December 31, 2025 on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip Montana (the AOC) as required by the Montana Department of Environmental Quality. It is possible that each co-owner of Colstrip will be required, at some future point, to post additional financial assurance to support further performance by the operator of closure and remediation actions under the AOC.

For additional information on AROs, see Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency and the reasons to the effect that it cannot be reasonably estimated are disclosed. A loss contingency will also be disclosed when it is reasonably possible that a liability has been incurred if the estimate

or range of potential loss is material. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

For additional information on contingencies, see Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations, or cash flows, as discussed below.

Energy Risk Management

PGE has an Executive Risk Committee (ERC) whose primary purpose is to oversee, guide, and support the prudent management of the Company's risks, as well as review and recommend energy portfolio risk limits that are subject to approval by the Audit and Risk Committee of the PGE Board of Directors. The ERC's responsibilities include risk reporting to provide visibility into portfolio risk and manage alignment with the Company's risk strategy and tolerances, providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market, liquidity, and credit risk management related to the Company's energy portfolio management activities. The ERC consists of officers and Company representatives with responsibility for risk management, finance and accounting, information technology, utility operations, legal, and rates and regulatory affairs.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase and sale contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants, and the sale of natural gas in excess of amounts needed for the Company's natural gas-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: i) forward contracts, which may involve physical delivery of an energy commodity; ii) financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and iii) option contracts to mitigate risk that arises from market fluctuations of commodity prices. The Company does not intend to engage in trading activities for non-retail purposes.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized losses recorded as of December 31, 2025 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Commodity contracts:							
Electricity	$ (9)	$ 2	$ 4	$ 3	$ 3	$ 17	$ 20
Natural gas	136	20	3	2	—	—	161
Net unrealized loss	$ 127	$ 22	$ 7	$ 5	$ 3	$ 17	$ 181

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. Energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel or Revenues, net in the statements of income and expected to be included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risk through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE employs a hedging strategy to mitigate its exposure to fluctuations in the Canadian exchange rate.

As of December 31, 2025, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2025, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as deemed necessary.

As of December 31, 2025, the total fair value and carrying amounts, excluding unamortized debt expense, by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2026	2027	2028	2029	2030	There-after
First Mortgage Bonds	$ 4,205	$ 4,560	$ —	$ 160	$ 100	$ 200	$ 325	$ 3,775
Pollution Control Revenue Bonds	106	119	—	—	—	—	—	119
Total	$ 4,311	$ 4,679	$ —	$ 160	$ 100	$ 200	$ 325	$ 3,894

As of December 31, 2025, PGE had no long-term debt instruments subject to interest rate risk exposure.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. The Company manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. PGE also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by

counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, within certain limits, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimates are used to provide an allowance for uncollectible accounts receivable related to retail sales to address such risk.

As of December 31, 2025, PGE's credit risk exposure was $19 million for commodity activities, of which $13 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature in 2026. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade counterparties include those with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit, and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington. These contracts currently provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public utility districts*" in Note 16, Commitments and Guarantees in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

Report of Independent Registered Public Accounting Firm (PCAOB ID 34) 79

Consolidated Statements of Income for the years ended December 31, 2025, 2024, and 2023 82

Consolidated Statements of Comprehensive Income for the years ended December 31, 2025, 2024, and 2023 83

Consolidated Balance Sheets as of December 31, 2025 and 2024 84

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2025, 2024, and 2023 86

Consolidated Statements of Cash Flows for the years ended December 31, 2025, 2024, and 2023 87

Notes to Consolidated Financial Statements 89

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance

with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Accounting — Refer to Notes 2 and 7 to the consolidated financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the "OPUC"), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon, and to wholesale rate regulation by the Federal Energy Regulatory Commission (the "FERC"). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts certain financial statement line items and disclosures.

The Company's rates are subject to regulatory rate-setting processes and annual earnings oversight. Because the OPUC and the FERC set the rates the Company is allowed to charge customers based on allowable costs, including a reasonable return on equity, the Company applies accounting standards that require the financial statements to reflect the effects of rate regulation. The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's cost of providing service to retail customers. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard. The Company assesses whether the regulatory assets and regulatory liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs, and factors such as changes in applicable regulatory and political environments. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the OPUC and the FERC will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to its pervasive impact on the Company's financial statements and the significant judgments made by management to support its assertions about certain account balances and disclosures. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC or FERC, including decisions regarding the prudency of costs which have been deferred as regulatory assets, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and significant auditor judgment to evaluate management estimates and the subjectivity of audit evidence.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the OPUC included the following, among others:

•We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as electric utility plant; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

•We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

•We read relevant regulatory orders issued by the OPUC and the FERC for the Company, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the OPUC's and the FERC's treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.

•We obtained an analysis from management, regarding probability of recovery of regulatory assets or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 17, 2026

We have served as the Company's auditor since 2004.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2025	2024	2023
Revenues:			
Revenues, net	$ 3,555	$ 3,480	$ 2,912
Alternative revenue programs, net of amortization	21	(40)	11
Total Revenues	3,576	3,440	2,923
Operating expenses:			
Purchased power and fuel	1,411	1,418	1,190
Generation, transmission and distribution	450	436	374
Administrative and other	392	403	341
Depreciation and amortization	578	496	458
Taxes other than income taxes	190	175	164
Total operating expenses	3,021	2,928	2,527
Income from operations	555	512	396
Interest expense, net	232	211	173
Other income:			
Allowance for equity funds used during construction	18	23	19
Miscellaneous income, net	18	26	31
Other income, net	36	49	50
Income before income taxes	359	350	273
Income tax expense	53	37	45
Net income	$ 306	$ 313	$ 228
Weighted-average shares outstanding (in thousands):			
Basic	110,471	103,946	97,760
Diluted	110,739	104,159	97,952
Earnings per share:			
Basic	$ 2.77	$ 3.02	$ 2.33
Diluted	$ 2.77	$ 3.01	$ 2.33

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2025	2024	2023
Net income	$ 306	$ 313	$ 228
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of an immaterial amount in all three years	—	1	(1)
Comprehensive income	$ 306	$ 314	$ 227

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31, 2025	2024
ASSETS		
Current assets:		
Cash and cash equivalents	$ 76	$ 12
Accounts receivable, net	460	456
Inventories, at average cost:		
Materials and supplies	99	92
Fuel	25	22
Regulatory assets—current	168	205
Other current assets	244	238
Total current assets	1,072	1,025
Electric utility plant:		
In service	15,996	14,863
Accumulated depreciation and amortization	(5,419)	(5,085)
In service, net	10,577	9,778
Construction work-in-progress	416	567
Electric utility plant, net	10,993	10,345
Regulatory assets—noncurrent	619	632
Nuclear decommissioning trust	42	30
Non-qualified benefit plan trust	36	34
Other noncurrent assets	468	478
Total assets	$ 13,230	$ 12,544

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31, 2025	2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 330	$ 365
Liabilities from price risk management activities—current	158	147
Current portion of long-term debt	—	170
Current portion of finance lease obligations	27	27
Accrued expenses and other current liabilities	478	410
Total current liabilities	993	1,119
Long-term debt, net of current portion	4,662	4,354
Regulatory liabilities—noncurrent	1,490	1,440
Deferred income taxes	601	564
Deferred investment tax credits	194	61
Unfunded status of pension and postretirement plans	107	140
Liabilities from price risk management activities—noncurrent	56	72
Asset retirement obligations	299	292
Non-qualified benefit plan liabilities	70	74
Finance lease obligations, net of current portion	263	276
Other noncurrent liabilities	362	358
Total liabilities	9,097	8,750
Commitments and contingencies (see notes)		
Shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 115,559,079 and 109,342,251 shares issued and outstanding as of December 31, 2025 and 2024, respectively	2,382	2,118
Accumulated other comprehensive loss	(4)	(4)
Retained earnings	1,755	1,680
Total shareholders' equity	4,133	3,794
Total liabilities and shareholders' equity	$ 13,230	$ 12,544

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In millions, except share and per share amounts)

	Common Stock		Accumulated Other Comprehensive	Retained	
	Shares	Amount	Loss	Earnings	Total
Balance as of December 31, 2022	89,283,353	$ 1,249	$ (4)	$ 1,534	$ 2,779
Issuances of shares pursuant to equity forward sales agreement	11,615,000	485	—	—	485
Shares issued pursuant to equity-based plans	261,256	3	—	—	3
Stock-based compensation	—	13	—	—	13
Dividends declared ($1.8775 per share)	—	—	—	(188)	(188)
Net income	—	—	—	228	228
Other comprehensive (loss)	—	—	(1)	—	(1)
Balance as of December 31, 2023	101,159,609	1,750	(5)	1,574	3,319
Issuances of shares pursuant to equity forward sales agreement	7,921,022	346			346
Shares issued pursuant to equity-based plans	261,620	2	—	—	2
Stock-based compensation	—	20	—	—	20
Dividends declared ($1.9750 per share)	—	—	—	(207)	(207)
Net income	—	—	—	313	313
Other comprehensive income	—	—	1	—	1
Balance as of December 31, 2024	109,342,251	2,118	(4)	1,680	3,794
Issuance of shares pursuant to equity agreements	5,919,618	250	—	—	250
Shares issued pursuant to equity-based plans	297,210	2	—	—	2
Stock-based compensation	—	12	—	—	12
Dividends declared ($2.0750 per share)	—	—	—	(231)	(231)
Net income	—	—	—	306	306
Balance as of December 31, 2025	115,559,079	$ 2,382	$ (4)	$ 1,755	$ 4,133

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2025	2024	2023
Cash flows from operating activities:			
Net income	$ 306	$ 313	$ 228
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	578	496	458
Deferred income taxes	37	23	8
Allowance for equity funds used during construction	(18)	(23)	(19)
Pension and other postretirement benefits	12	6	5
Alternative revenue programs	(21)	40	(11)
Stock-based compensation	16	24	17
Regulatory assets	24	(126)	20
Regulatory liabilities	(21)	(20)	24
Tax credit sales	179	112	24
Other non-cash income and expenses, net	64	57	40
Changes in working capital:			
Accounts receivable and unbilled revenues	(16)	(66)	(29)
Margin deposits	9	(33)	24
Accounts payable and accrued liabilities	44	47	(166)
Margin deposits from wholesale counterparties	16	—	(135)
Other working capital items, net	(10)	(12)	(20)
Contribution to pension and other postretirement plans	(24)	(19)	(14)
Contribution to non-qualified employee benefit trust	(10)	(10)	(7)
Asset retirement obligation settlements	(13)	(16)	(25)
Other, net	(34)	(15)	(2)
Net cash provided by operating activities	1,118	778	420
Cash flows from investing activities:			
Capital expenditures	(1,189)	(1,268)	(1,358)
Purchases of nuclear decommissioning trust securities	(9)	(8)	(1)
Sales of nuclear decommissioning trust securities	4	2	1
Other, net	(2)	(23)	—
Net cash used in investing activities	(1,196)	(1,297)	(1,358)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2025	2024	2023
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 310	$ 670	$ 600
Payments on long-term debt	(170)	(130)	(260)
Proceeds from issuances of common stock, net of issuance costs	250	346	485
Issuance (maturities) of commercial paper, net	—	(146)	146
Dividends paid	(225)	(200)	(179)
Other	(23)	(14)	(14)
Net cash provided by financing activities	142	526	778
Change in cash and cash equivalents	64	7	(160)
Cash and cash equivalents, beginning of year	12	5	165
Cash and cash equivalents, end of year	$ 76	$ 12	$ 5
Supplemental disclosures of cash flow information:			
Cash paid (received) for:			
Interest, net of amounts capitalized	$ 198	$ 174	$ 136
Income taxes, net	(162)	(90)	12
Non-cash investing and financing activities:			
Accrued capital additions	126	184	212
Accrued dividends payable	63	57	51

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically-integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company also participates in the wholesale market by purchasing and selling electricity, natural gas, and environmental credits in an effort to meet the needs of, and obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. In addition, PGE performs portfolio management and wholesale market sales services for third parties in the region. The Company continues to develop products and service offerings for the benefit of retail and wholesale customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGE's corporate headquarters. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, State-approved service area is located entirely within the State. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2025, PGE served approximately 960,000 retail customers with a service area population of approximately 2 million.

As of December 31, 2025, PGE had 2,877 employees in its workforce, with 666 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement covers 602 employees and expires February 2028, and the other covers 64 employees and expires August 2027. PGE also utilizes independent contractors and temporary personnel to supplement its workforce.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 18, Jointly-Owned Plant. Intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Reclassifications

To conform with current year presentation, the Company has reclassified $19 million and $14 million from Other, net to Contribution to pension and other postretirement plans in the operating activities section of the consolidated statements of cash flows for the years ended December 31, 2024 and 2023, respectively.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $59 million as of December 31, 2025 and $12 million as of December 31, 2024 included within Cash and cash equivalents in the consolidated balance sheets.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and State (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning eight calendar days after the invoice due date. Accounts that are inactivated due to nonpayment are charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 53 business days after the due date of the final invoice.

Provisions for uncollectible accounts receivable and unbilled revenues related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of accounts receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for accounts receivable and unbilled revenues. For more information on PGE's provision for uncollectible accounts receivable and unbilled revenues see "*Accounts Receivable, Net"* in Note 4, Balance Sheet Components.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. The balance of provisions for uncollectible accounts receivable was immaterial and there have been no material write-offs of accounts receivable related to wholesale sales in 2025, 2024, or 2023.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, and foreign currency. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated statements of income, offset by the effects of regulatory accounting when it is expected that the gain or loss upon settlement will be reflected in future retail prices. Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net variable power costs (NVPC).

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, the Company recognizes a realized gain or loss on the derivative instrument.

Physically settled electricity and natural gas sale and purchase transactions are recorded in Revenues, net and Purchased power and fuel expense, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are

included within Other current assets in the consolidated balance sheets and were $116 million as of December 31, 2025 and $125 million as of December 31, 2024. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheets and there were $123 million and $18 million as of December 31, 2025 and 2024, respectively.

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, as well as fuel, which includes natural gas, coal, and oil for use in the Company's generating plants. Periodically, the Company assesses inventory for purposes of determining that inventories are recorded at the lower of average cost or net realizable value.

Electric Utility Plant

Capitalization Policy

Electric utility plant is capitalized at original cost, which includes direct labor, materials and supplies, and contractor costs, as well as allocable overheads such as engineering, supervision, employee benefits, certain administrative costs directly related to construction, and an allowance for funds used during construction (AFUDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls performed under long-term service agreements at PGE's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining FERC licenses for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work-in-progress in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, PGE may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. Costs related to recently completed plant that are disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFUDC, which is intended to represent the Company's cost of funds used for construction purposes, based on the rate granted in the latest general rate case (GRC) for equity funds and the cost of actual borrowings for debt funds. AFUDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 6.7% in 2025, 6.7% in 2024, and 6.5% in 2023. AFUDC from borrowed funds, reflected as a reduction to Interest expense, net, was $11 million in 2025, $15 million in 2024, and $13 million in 2023. AFUDC from equity funds, included in Other income, net, was $18 million in 2025, $23 million in 2024, and $19 million in 2023.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.6% in 2025, and 3.5% in 2024 and 3.4% in 2023. A component of depreciation expense includes estimated asset retirement removal costs allowed in customer prices.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. In 2021, PGE completed a depreciation study based on 2019 data, with an order received from the OPUC in December 2021 authorizing new depreciation rates effective May 9, 2022.

Generation plants are depreciated using a life-span methodology, which is designed to recover the plant investment by the estimated retirement dates, which range from 2035 to 2064. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Transmission	58
Distribution	50
Energy Storage	16
General	17

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, if applicable, and included in Regulatory liabilities.

Intangible plant consists primarily of computer software development costs, which are amortized over either three, five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $622 million and $611 million as of December 31, 2025 and 2024, respectively, with amortization expense of $76 million in 2025, $72 million in 2024, and $61 million in 2023. Future estimated amortization expense as of December 31, 2025 is as follows: $79 million in 2026; $73 million in 2027; $49 million in 2028; $29 million in 2029; and $17 million in 2030.

Marketable Securities

Nuclear decommissioning trust

The Nuclear decommissioning trust (NDT) reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. The NDT includes contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust

PGE's non-qualified benefit plans (NQBP) reflects assets held in trust to cover the obligations of PGE's NQBP and represents contributions made by the Company, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

All of PGE's investments in marketable securities included in NDT and NQBP trust assets on the consolidated balance sheets, are classified as equity or trading debt securities. These securities are classified as noncurrent because they are not available for use in operations. Such securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the NQBP trust assets are included in Other income, net. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold in the NDT and the NQBP are based on the first-in first-out method.

Other Investments

PGE has investments in non-marketable equity securities for which the Company does not have controlling financial interest however, based on PGE's ownership interest, are accounted for under the equity method of accounting. These investments are accounted for at cost, adjusted for the Company's proportionate share of the investee's earnings or losses, distributions received, and impairments, if any.

As of December 31, 2025 and 2024, equity method investments were $19 million and $13 million, respectively, recorded in Other noncurrent assets on the Company's consolidated balance sheets. For the years ended December 31, 2025, 2024, and 2023, the Company's share of net earnings or losses from equity method

investments were immaterial. PGE's share of earnings or losses are recorded as Miscellaneous income, net within Other income, net on the Company's consolidated statements of income.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent: i) probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process; or ii) current collections for future expected costs. Regulatory accounting is appropriate as long as: i) prices are established by, or subject to, approval by independent third-party regulators; ii) prices are designed to recover the specific enterprise's cost-of-service; and iii) in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the consolidated statement of income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include: i) increased competition that restricts PGE's ability to establish prices to recover specific costs; and ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews the criteria of regulatory accounting to verify that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of PGE's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 7, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a Power Cost Adjustment Mechanism (PCAM), as approved by the OPUC. Pursuant to the PCAM, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased power and fuel in the Company's consolidated statements of income, and includes wholesale sales, which are classified as Revenues, net in the consolidated statements of income.

The Company is subject to a portion of the business risk or benefit associated with the difference between actual and baseline NVPC by application of an asymmetrical deadband, which ranges from $15 million below to $30 million above baseline NVPC.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from, or refunded to, customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for the given year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.34% for 2025 and 9.5% for 2024.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in PGE's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. For the year ended December 31, 2025, PGE's actual NVPC was $6 million below baseline NVPC, which is within the established deadband range. Accordingly, there is no estimated refund

to customers under the PCAM for 2025. For the year ended December 31, 2024, actual NVPC was below baseline NVPC by $78 million, which was outside the established deadband range. Pursuant to the PCAM and related earnings test, because PGE's preliminary regulatory ROE was below 10.5%, there was no estimated refund to customers under the PCAM for 2024.

The Company also has a reliability contingency event (RCE) mechanism, which operates under the PCAM tariff. This mechanism was approved by the OPUC as part of the 2024 GRC proceedings. The RCE mechanism allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's Annual Power Cost Update Tariff (AUT), without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. This mechanism expired at the end of 2025.

For additional information concerning PCAM, see Note 7, Regulatory Assets and Liabilities.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated balance sheets. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques. The present value of estimated future decommissioning costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation included in Depreciation and amortization in the consolidated statements of income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is included in Depreciation and amortization expense in the Company's consolidated statements of income.

For additional information concerning the Company's AROs, see Note 8, Asset Retirement Obligations.

The difference between the timing of the recognition of ARO depreciation and accretion expenses and the amount included in customer prices is recorded as a regulatory asset or liability in the Company's consolidated balance sheets. As of December 31, 2025, PGE had a net regulatory asset related to Utility plant AROs in the amount of $6 million and a net regulatory asset related to Trojan decommissioning ARO activities of $161 million. As of December 31, 2024, PGE had a net regulatory liability related to Utility plant AROs in the amount of $7 million and a net regulatory asset related to Trojan decommissioning ARO activities of $161 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 7, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies, including environmental contingencies, are accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that a liability has been incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons why the estimate cannot be made.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in either the current or the subsequent reporting period, depending on the nature of the underlying event.

Gain contingencies are recognized when realized and are disclosed when material.

For additional information concerning the Company's contingencies, see Note 19, Contingencies.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the obligations of the NQBP recognized in net income and the unfunded position.

Revenue Recognition

Revenue is recognized when obligations under the terms of a contract with customers are satisfied. Generally, this satisfaction of performance obligations and transfer of control occurs and revenues are recognized as electricity is delivered to customers, including any services provided. The prices charged, and amount of consideration PGE receives in exchange for its services provided, are regulated by the OPUC or the FERC. PGE recognizes revenue through the following steps: i) identifying the contract with the customer; ii) identifying the performance obligations in the contract; iii) determining the transaction price; iv) allocating the transaction price to the performance obligations; and v) recognizing revenue when or as each performance obligation is satisfied.

Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $70 million in 2025, $63 million in 2024, and $56 million in 2023.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that remained unbilled to customers. The unbilled revenues estimate, which is included in Accounts receivable, net in the Company's consolidated balance sheets, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

As a rate-regulated utility, PGE, in certain situations, recognizes revenue to be billed to customers in future periods or defers the recognition of certain revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Alternative Revenue Programs

Revenues related to PGE's decoupling mechanism and Renewable Adjustment Clause (RAC) are considered earned under alternative revenue programs, as these amounts represent contracts with the regulator and not with customers. Such revenues are presented separately from revenues from contracts with customers and classified as Alternative revenue programs, net of amortization on the consolidated statements of income. The activity within this line item is comprised of current period deferral adjustments, which can either be a collection from or a refund to customers, and is net of any related amortization. When amounts related to alternative revenue programs are ultimately included in prices and customer bills, the amounts are included within Revenues, net, with an equal

and offsetting amount of amortization recorded on the Alternative revenue programs, net of amortization line item. Under the RAC, in 2024 and 2025, the Company has deferred amounts related to the Clearwater Wind Development (Clearwater). For further information, see *"Clearwater RAC"* within Note 7, Regulatory Assets and Liabilities.

In the 2022 GRC, parties reached an agreement that has eliminated PGE's decoupling mechanism upon the effective date of new customer prices pursuant to the case, May 9, 2022. Pursuant to the GRC Order, the OPUC adopted the agreement such that deferrals will not occur after 2022, although amortization of then previously recorded deferrals will continue as scheduled until collected or refunded in future customer prices and deferral continued through the end of 2022 on a prorated basis. Amounts deferred in 2022 continued to be amortized through the end of 2024.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Time-based and performance-based restricted stock unit (RSU) grant agreements provide that, if a grantee satisfies the "rule of 75" upon termination of employment for reasons other than cause, then: i) in the case of time-based RSUs, all unvested awards will vest; and ii) in the case of performance-based RSUs, the grantee will be eligible for full vesting, based on performance results, notwithstanding early termination. For purposes of these provisions, a recipient satisfies the rule of 75 if the recipient has no less than 5 years of service and the recipient's age plus years of service is at least 75. PGE accelerates recognition of compensation cost to the date the rule of 75 is met if the date is earlier than the vesting date of the award.

For additional information concerning the Company's Stock-Based Compensation, see Note 14, Stock-Based Compensation.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Investment Tax Credits (ITC) are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties. The weighted average life of the related properties is 16 years as of December 31, 2025. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized upon transfer or in future tax returns. Valuation allowances related to a discount incurred on transfer transactions that are recorded to deferred tax expense are currently recoverable through a regulatory asset.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $228 million and $179 million as of December 31, 2025 and 2024, respectively, and will primarily be reversed using the average rate assumption method to account for the refund to customers as the temporary differences reverse.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize

the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheets.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

The Inflation Reduction Act of 2022 (IRA) was signed into law on August 16, 2022. The IRA provides an election to transfer (i.e., sell) certain tax credits to unrelated third parties in exchange for cash consideration. PGE has elected an accounting policy to account for the transfer of Federal production tax credits (PTCs) and ITCs, including discounts, within the scope of Accounting Standards Codification 740 – Income Taxes. Tax credit sales are classified as an operating activity in the consolidated statements of cash flows, and included in Cash paid for income taxes, net within the supplemental disclosures of cash flow information. Derecognition of the transferred deferred tax asset occurs when the buyer obtains control of the tax credit.

Recent Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03 *Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*. ASU 2024-03 requires additional disclosure, in the notes to financial statements, of specified information about certain costs and expenses. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2027. Early adoption is permitted. PGE is assessing the impact of adoption on the consolidated financial statements and does not plan to early adopt the standard.

In December 2025, the FASB issued ASU 2025-10 *Government Grants (Topic 832): Accounting for Government Grants Received by Business Entities*. ASU 2025-10 adds guidance to ASC 832 on the recognition, measurement, and presentation of government grants. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2029. Early adoption is permitted. PGE is assessing the impact of adoption on the consolidated financial statements and does not plan to early adopt the standard.

Recently Adopted Accounting Pronouncements

For the year ended December 31, 2025, PGE adopted ASU 2023-09 *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. ASU 2023-09 amends Topic 740 to require entities to annually disaggregate the income tax rate reconciliation into prescribed categories, as well as to disclose income taxes paid disaggregated by jurisdiction. Because PGE elected to apply the guidance retrospectively, items for prior periods were reclassified to conform with current year presentation. As the standard relates only to disclosures, the adoption did not have a material impact on PGE's results of operation, financial position, or cash flows. For new required disclosures and further information, see Note 12, Income Taxes.

NOTE 3: REVENUE RECOGNITION

Disaggregated Revenue

The following table presents PGE's revenue, disaggregated by customer type (in millions):

	Year Ended December 31,		
	2025	2024	2023
Retail:			
Residential	$ 1,486	$ 1,457	$ 1,263
Commercial	969	914	800
Industrial	536	435	349
Direct access customers	41	33	27
Subtotal	3,032	2,839	2,439
Alternative revenue programs, net of amortization	21	(40)	11
Other accrued revenues, net	17	16	(3)
Total retail revenues	3,070	2,815	2,447
Wholesale revenues *	418	558	418
Other operating revenues	88	67	58
Total revenues	$ 3,576	$ 3,440	$ 2,923

* Wholesale revenues include $203 million, $273 million, and $185 million related to physical electricity commodity contract derivative settlements for the years ended December 31, 2025, 2024, and 2023, respectively. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers as defined by GAAP, pursuant to Topic 606. For further information, see Note 6, Risk Management.

Retail Revenues

The Company's primary revenue source is the sale of electricity to customers at regulated tariff-based prices. Retail customers are classified as residential, commercial, or industrial. Residential customers include single- family housing, multiple family housing (such as apartments, duplexes, and town homes), manufactured homes, and small farms. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating and summer cooling seasons. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers and are also sensitive to the effects of weather, although to a lesser extent than residential customers. Commercial customers include most businesses, small industrial companies, and public street and highway lighting accounts. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having a less significant impact on energy use by this customer class.

In accordance with state regulations, PGE's retail customer prices are based on the Company's cost-of-service and determined through GRC proceedings and various tariff filings with the OPUC. Additionally, the Company offers pricing options that include a daily market price option, various time-of-use options, and several renewable energy options.

Retail revenue is billed based on monthly meter readings taken throughout the month.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct services that are substantially the same and have the same pattern of transfer to the customer that is satisfied over time as customers simultaneously receive and consume the benefits provided. PGE applies the invoice method to measure its progress towards satisfactorily completing its performance obligations.

Pursuant to regulation by the OPUC, PGE is mandated to maintain several tariff schedules to collect funds from customers for programs that benefit the general public, such as conservation, low-income housing, energy efficiency, renewable energy programs, and privilege taxes. For such programs, PGE generally collects the funds

and remits the amounts to third party agencies that administer the programs. In these arrangements, PGE is considered to be an agent, as PGE's performance obligation is to facilitate a transaction between customers and the administrators of these programs. Therefore, such amounts are presented on a net basis and do not appear in Revenues, net within the consolidated statements of income.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer its current long-term wholesale contracts. In addition, the Company performs portfolio management and wholesale market services for third parties in the region and sells environmental credits in the wholesale marketplace. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow PGE to purchase and sell electricity within the region depending upon: i) the relative price and availability of power; ii) hydro, solar, and wind conditions; and iii) daily and seasonal retail demand.

PGE's Wholesale revenues consist primarily of short-term electricity sales to utilities and power marketers that consist of single performance obligations that are satisfied as energy is transferred to the counterparty. The Company may choose to net certain purchase and sale transactions in which it would simultaneously receive and deliver physical power with the same counterparty; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled and recorded in Wholesale revenues.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resale, excess fuel sales, utility pole attachment revenues, and other electric services provided to customers.

Arrangements with Multiple Performance Obligations

Certain contracts with customers, primarily wholesale, may include multiple performance obligations. For such arrangements, PGE allocates revenue to each performance obligation based on its relative standalone selling price. The Company generally determines standalone selling prices based on the prices charged to customers.

NOTE 4: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable, net includes $180 million and $177 million of unbilled revenues as of December 31, 2025 and 2024, respectively. Accounts receivable is net of an allowance for uncollectible accounts of $13 million as of December 31, 2025 and $12 million as of December 31, 2024. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2025	2024	2023
Balance as of beginning of year	$ 12	$ 9	$ 12
Increase/(decrease) in provision	12	11	5
Amounts written off, less recoveries	(11)	(8)	(8)
Balance as of end of year	$ 13	$ 12	$ 9

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31, 2025	2024
Other current assets:		
Prepaid expenses	$ 96	$ 81
Margin deposits	116	125
Assets from price risk management activities	32	32
	$ 244	$ 238
Accrued expenses and other current liabilities:		
Regulatory liabilities—current	$ 73	$ 53
Accrued employee compensation and benefits	87	80
Accrued dividends payable	63	57
Accrued interest payable	53	49
Accrued taxes payable	38	36
Margin deposits from wholesale counterparties	21	5
Other	143	130
	$ 478	$ 410

Electric Utility Plant, Net

Electric utility plant, net consist of the following (in millions):

	As of December 31, 2025	2024
Electric utility plant [(1)]:		
Generation	$ 5,649	$ 5,510
Transmission [(2)]	1,626	1,420
Distribution [(2)]	6,189	5,714
General	931	1,025
Energy storage	613	222
Intangible	988	972
Total in service	15,996	14,863
Accumulated depreciation and amortization	(5,419)	(5,085)
Total in service, net	10,577	9,778
Construction work-in-progress	416	567
Electric utility plant, net	$ 10,993	$ 10,345

(1) On January 1, 2025, FERC Order 898 reclassified certain assets between primary functions for ratemaking purposes. In 2025 and going forward, tangible assets are classified consistent with the FERC's updated functional classification. Reclassifications were completed as of January 1, 2025 of $22 million of Generation, $21 million of Transmission, $87 million of Distribution, $(132) million of General, and $2 million of Energy storage plant.

(2) On July 2, 2025, the FERC approved PGE's request to classify the functional asset classification of certain 57kV facilities from Distribution to Transmission to align classification with the primary function of these assets. As a result, PGE reclassified $84 million of Electric utility plant in-service assets from Distribution to Transmission.

NOTE 5: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company’s consolidated balance sheets, for which it is practicable to estimate fair value for each reporting period. The Company then classifies these financial assets and liabilities based on a fair value hierarchy applied to

prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy and application to the Company are discussed below.

Level 1	Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.
Level 2	Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.
Level 3	Pricing inputs include significant inputs that are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the years ended December 31, 2025 and 2024, except those presented in this note.

The Company's financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	December 31, 2025				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Cash equivalents	$ 59	$ —	$ —	$ —	$ 59
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	14	11	—	—	25
Corporate credit	—	10	—	—	10
Money market funds measured at NAV [2]	—	—	—	7	7
Non-qualified benefit plan trust: [3]					
Debt securities—domestic government	1	—	—	—	1
Paid Leave Oregon Trust:					
Money market funds measured at NAV [2]	—	—	—	7	7
Price risk management activities: [1] [4]					
Electricity	—	29	1	—	30
Natural gas	—	3	—	—	3
	$ 74	$ 53	$ 1	$ 14	$ 142
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$ —	$ 13	$ 37	$ —	$ 50
Natural gas	—	160	4	—	164
	$ —	$ 173	$ 41	$ —	$ 214

(1)Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2)Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.

(3)Excludes insurance policies of $35 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 6, Risk Management.

	December 31, 2024				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Cash equivalents	$ 12	$ —	$ —	$ —	$ 12
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	10	6	—	—	16
Corporate credit	—	7	—	—	7
Money market funds measured at NAV [2]	—	—	—	7	7
Non-qualified benefit plan trust: [3]					
Debt securities—domestic government	2	—	—	—	2
Paid Leave Oregon Trust:					
Money market funds measured at NAV [2]	—	—	—	4	4
Price risk management activities: [1] [4]					
Electricity	—	18	1	—	19
Natural gas	—	15	—	—	15
	$ 24	$ 46	$ 1	$ 11	$ 82
Liabilities:					
Price risk management activities: [1] [4]					
Electricity	$ —	$ 25	$ 31	$ —	$ 56
Natural gas	—	159	4	—	163
	$ —	$ 184	$ 35	$ —	$ 219

(1)Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2)Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3)Excludes insurance policies of $32 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 6, Risk Management.

Cash equivalents are highly liquid investments with maturities of three months or less at the date of acquisition and primarily consist of money market funds. Such funds seek to maintain a stable net asset value and are comprised of short-term, government funds. Policies of such funds require that the weighted-average maturity of securities held by the funds do not exceed 90 days and investors have the ability to redeem shares daily at the net asset value of the respective fund. Cash equivalents are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for money market fund prices include published exchanges such as the National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

Assets held in the NDT, NQBP, and Paid Leave Oregon trusts are recorded at fair value in PGE's consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

Debt securities—PGE invests in highly-liquid United States Treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in

valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

The money market funds in the NDT and Paid Leave Oregon Trust are valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Assets and liabilities from price risk management activities, recorded at fair value in PGE's consolidated balance sheets, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 6, Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as forward commodity prices and interest rates. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include commodity forwards, futures, and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer-term commodity forwards, futures, and swaps.

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Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities is presented below:

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2025:							
Electricity physical forwards	$ —	$ 37	Discounted cash flow	Electricity forward price (per MWh)	$ 22.99	$ 94.65	$ 59.28
Natural gas financial swaps	—	4	Discounted cash flow	Natural gas forward price (per Dth)	1.67	2.76	2.15
Electricity financial futures	1	—	Discounted cash flow	Electricity forward price (per MWh)	31.00	84.00	52.13
	$ 1	$ 41					
As of December 31, 2024:							
Electricity physical forwards	$ —	$ 28	Discounted cash flow	Electricity forward price (per MWh)	$ 14.00	$ 99.68	$ 59.43
Natural gas financial swaps	—	4	Discounted cash flow	Natural gas forward price (per Dth)	1.86	6.53	2.68
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	27.00	110.00	70.55
	$ 1	$ 35					

The significant unobservable inputs used in the Company's fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter-term contracts, PGE employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long-term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer-term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a quarterly basis by the Company.

The Company's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31, 2025	2024
Net liabilities from price risk management activities as of beginning of year	$ 34	$ 45
Net realized and unrealized losses *	22	25
Net transfers from Level 3 to Level 2	(16)	(36)
Net liabilities from price risk management activities as of end of year	$ 40	$ 34
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 27	$ 30

* Includes $5 million in net realized gains in both 2025 and 2024.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers into and out of Level 3 at the end of the reporting period for all of its derivative instruments.

During the years ended December 31, 2025 and 2024, there were no transfers into Level 3 from Level 2. Transfers from Level 3 are reflected in the table above.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2025, the carrying amount of PGE's long-term debt was $4,662 million, net of $17 million of unamortized debt expense, and its estimated aggregate fair value was $4,311 million. As of December 31, 2024, the carrying amount of PGE's long-term debt was $4,524 million, net of $15 million of unamortized debt expense, with an estimated aggregate fair value of $3,963 million.

For fair value information concerning the Company's pension plan assets, see Note 11, Employee Benefits.

NOTE 6: RISK MANAGEMENT

PGE participates in the wholesale marketplace to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of, and secure reasonably priced power for, its retail customers, manage risk, and administer the Company's long-term wholesale contracts. Wholesale market transactions include purchases and sales of both power and fuel resulting from economic dispatch decisions with respect to Company-owned generating resources. The Company also performs portfolio management and wholesale market sales services for third parties in the region and sells environmental credits in the wholesale marketplace. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the consolidated balance sheets, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the consolidated statements of income. In

accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not intend to engage in trading activities for non-retail purposes.

PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31, 2025	2024
Current assets:		
Commodity contracts:		
Electricity	$ 29	$ 18
Natural gas	3	14
Total current derivative assets[1]	32	32
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Natural gas	—	1
Total noncurrent derivative assets[1]	1	2
Total derivative assets[2]	$ 33	$ 34
Current liabilities:		
Commodity contracts:		
Electricity	$ 19	$ 32
Natural gas	139	115
Total current derivative liabilities	158	147
Noncurrent liabilities:		
Commodity contracts:		
Electricity	31	24
Natural gas	25	48
Total noncurrent derivative liabilities	56	72
Total derivative liabilities[2]	$ 214	$ 219

(1)Total current derivative assets is included in Other current assets, and Total noncurrent derivative assets is included in Other noncurrent assets on the consolidated balance sheets.
(2)As of December 31, 2025 and 2024, no commodity derivative assets or liabilities were designated as hedging instruments.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through December 31, 2035, were as follows (in millions):

	As of December 31, 2025		2024	
Commodity contracts:				
Electricity	1	MWh	2	MWh
Natural gas	224	Dth	199	Dth
Foreign currency contracts	$ 9	Canadian	$ 34	Canadian

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the consolidated balance sheet. In the case of default on, or termination of, any contract under the master netting arrangements, such agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for

scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2025, gross amounts included as Price risk management liabilities subject to master netting agreements were $41 million, all of which was for natural gas, for which PGE has posted $14 million collateral. As of December 31, 2024, gross amounts included as Price risk management liabilities subject to master netting agreements were $41 million, entirely for natural gas, for which PGE had posted $16 million collateral.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,		
	2025	2024	2023
Commodity contracts:			
Electricity	$ (26)	$ (17)	$ (130)
Natural Gas	206	30	357
Foreign currency contracts	(1)	(1)	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $24 million, net gains of $5 million, and net losses of $403 million for the years ended December 31, 2025, 2024, and 2023, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized losses recorded as of December 31, 2025 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Commodity contracts:							
Electricity	$ (9)	$ 2	$ 4	$ 3	$ 3	$ 17	$ 20
Natural gas	136	20	3	2	—	—	161
Net unrealized loss	$ 127	$ 22	$ 7	$ 5	$ 3	$ 17	$ 181

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2025 was $208 million. The Company has posted $72 million in collateral, consisting of $59 million of cash and $13 million of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2025, the cash requirement to either post as collateral or settle the instruments immediately would have been $146 million. As of December 31, 2025, PGE had no cash collateral posted for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's consolidated balance sheet.

As of December 31, 2025, PGE received from counterparties $26 million in collateral, consisting of $5 million of letters of credit and $21 million of cash. The obligation to return cash collateral held for derivative instruments is included in Accrued expenses and other current liabilities on the Company's consolidated balance sheets.

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. Credit risk may be concentrated to the extent PGE's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. The Company manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. PGE also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 5, Fair Value of Financial Instruments.

NOTE 7: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (dollars in millions):

		As of December 31, 2025			2024
	Remaining Amortization Period	Earning a Return [1]	Not Earning a Return	Total	Total
Regulatory assets:					
Price risk management	(2)	$ —	$ 181	$ 181	$ 185
Pension plans	(3)	—	64	64	84
Trojan decommissioning activities	2059	—	161	161	161
February 2021 ice storm and damage	2029	46	—	46	58
January 2024 storm and damage	(4)	48	—	48	46
Reliability contingency events	(4)	90	—	90	90
2020 Labor Day wildfire	2029	19	—	19	24
Wildfire mitigation	(5)	42	—	42	43
Other	Various	74	62	136	146
Total regulatory assets		$ 319	$ 468	$ 787	$ 837
Regulatory liabilities:					
Asset retirement removal costs	(6)	$ 1,245	$ —	$ 1,245	$ 1,199
Deferred income taxes	(7)	228	—	228	179
Clearwater RAC	(8)	22	—	22	40
Other	Various	58	11	69	75
Total regulatory liabilities		$ 1,553	$ 11	$ 1,564	$ 1,493

(1)Earning a return includes either interest on the regulatory asset or liability, or inclusion of the regulatory asset or liability as an increase or decrease to rate base at the allowed rate of return.
(2)No amortization period in accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains on derivative instruments until settlement.
(3)Recovery expected over the average service life of employees.
(4)Amortization period has yet to be decided.

(5)The current portion of the balance is expected to amortize by May 31, 2026. The non-current portion of the balance relates to incremental amounts deferred between January 1, 2024 and December 31, 2025 and are not yet approved for amortization.
(6)Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(7)Refund expected as the balance is reversed using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.
(8)Amortization began on March 1, 2025.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 6, Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic pension and postretirement benefit costs. For further information, see Note 11, Employee Benefits.

Trojan decommissioning activities represents the deferral of ongoing costs and adjustments to the Trojan ARO associated with monitoring spent nuclear fuel at Trojan, net of amortization of customer collections. In addition, proceeds received from the United States Department of Energy (USDOE) for the reimbursement of costs to monitor the ISFSI is deferred and offsets customer collections. For additional information concerning Trojan decommissioning activities, see Note 8, Asset Retirement Obligations.

February 2021 ice storm and damage represents the costs incurred to repair damage to PGE's transmission and distribution systems and restore power to customers as a result of the historic storms that ultimately led Oregon's Governor to declare a state of emergency in February 2021.

January 2024 storm and damage represents the costs incurred to repair damage to PGE's transmission and distribution systems and restore power to customers as a result of the historic storm that ultimately led Oregon's Governor to declare a state of emergency in January 2024. The declared state of emergency allows PGE to seek recovery of incremental storm expenses through the OPUC pre-authorized emergency deferral mechanism, subject to the application of an earnings test. On February 9, 2024, PGE filed a Notice of Deferral with the OPUC, under Docket UM 2190, related to the emergency restoration costs for the January storm, and through December 31, 2025 the Company has deferred $48 million, including interest, under the deferral. PGE believes the amounts deferred as of December 31, 2025 are probable of recovery under the emergency deferral mechanism, and no earnings test adjustment is necessary as PGE's 2024 regulated return on equity did not exceed the OPUC's authorized rate. The OPUC has significant discretion in making the final determination of recovery and their conclusion of overall prudence, including application of the earnings test, could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

Reliability contingency events represents costs deferred under the reliability contingency event (RCE) mechanism, which allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's AUT, without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. As of December 31, 2025, PGE's deferred balance related to RCEs was $90 million, which includes $88 million related to RCEs deferred in 2024 and $2 million related to RCEs deferred in 2025. PGE files the results of the PCAM annually with the OPUC no later than July 1, initiating a regulatory review process that typically results in a final determination and order from the OPUC by the end of the year of filing, with any resulting refund or collection impacting customer prices effective in the following year. RCE costs incurred in 2024 and in 2025 will be included in the PCAM for 2024 and 2025. The Company filed the PCAM for 2024 on July 1, 2025, and the proceeding is on-going with a Commission decision anticipated in the first quarter of 2026. The Company expects to file the PCAM for 2025 no later than July 1, 2026. PGE believes the deferred amounts as of December 31, 2025 are probable of recovery. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

2020 Labor Day wildfire represents incurred costs to replace and rebuild PGE facilities damaged by the fires, as well as address fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE's property and right-of-way.

Wildfire mitigation represents incremental costs and investments made by PGE related to intensifying efforts on its system to mitigate the risk of wildfire and improve resiliency to wildfire damage under Oregon Senate Bill 762, enacted in 2021. These efforts include enhanced tree and brush clearing, hardening and undergrounding equipment, and making emergency plans in close partnership with various land and emergency management agencies to further expand the use of a public safety power shutoff, when the risk warrants. In December 2025, PGE submitted its 2026-2028 risk-based Wildfire Mitigation Plan. This plan is subject to annual updates, as well as the OPUC's approval.

As of December 31, 2025 and December 31, 2024, PGE's deferred balance related to wildfire mitigation was $42 million and $43 million, respectively. The 2025 balance is comprised of:

- *2024 AAC* - Beginning January 1, 2024, and in conjunction with the Company's 2024 GRC proceeding, PGE removed the $24 million of wildfire mitigation operations and maintenance (O&M) expense recovery from base rates, with the intent of recovering the current year forecasted O&M expense within the automatic adjustment clause (AAC) in a separate tariff. On February 16, 2024, PGE submitted an advice filing to the OPUC to update the tariff to reflect prospective wildfire mitigation costs for 2024, which included $45 million of O&M expense and $4 million for the revenue requirement of capital placed in service. On July 23, 2024, the OPUC reached a decision that allowed PGE to begin collecting $24 million of O&M expense and $4 million for the revenue requirement of capital placed in service. Collection will occur over a nine-month period, which began August 1, 2024. Although the approved amount of collections in 2024 is less than actual costs, PGE does not believe it is precluded from deferring such costs and believes they are prudently incurred and probable of recovery. Any differences between actual expense and customer collections will be recorded as regulatory assets or liabilities within the AAC balancing account, which will be subject to a prudency review, but will not be subject to an earnings test. As of December 31, 2025, there was $23 million deferred as a regulatory asset in the balancing account related to 2024. PGE submitted an additional filing to seek recovery of the remaining O&M expense on October 17, 2025. On February 13, 2026, PGE filed a Stipulation reflecting an all-party settlement that, if approved by the OPUC, would allow PGE recovery of its deferred amounts related to 2024 O&M. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.
- *2025 AAC* - In conjunction with PGE's filed 2025 Wildfire Mitigation Plan, PGE submitted a series of advice filings in 2025 with the intent of recovering the $56 million related to O&M and $12 million related to the capital revenue requirement in a two-phased approach. The first phase, which includes $24 million of O&M to be collected over a twelve-month period, was approved by the OPUC in February 2025, with a tariff effective date of March 1, 2025. The second phase, which was approved by the OPUC in May 2025, will be collected over a twelve-month period beginning June 1, 2025, and includes $12 million of O&M and the entire $12 million related to capital revenue requirement. Although the OPUC has only approved a portion of PGE's 2025 wildfire mitigation O&M, PGE does not believe it is precluded from deferring such costs. Any differences between actual expense and customer collections will be recorded as regulatory assets or liabilities within the AAC balancing account, which will be subject to a prudence review, but will not be subject to an earnings test. As of December 31, 2025, there was $19 million deferred as a regulatory asset in the balancing account related to 2025. PGE submitted an additional filing to seek recovery of the remaining 2025 forecasted O&M expense on October 17, 2025. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

Asset retirement removal costs represents the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Deferred income taxes represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of reversing the excess deferred income tax balance cannot occur more rapidly than over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 12, Income Taxes.

Clearwater RAC represents all costs and benefits associated with the Clearwater wind facility. Under the RAC, during 2023, the Company submitted a filing for Clearwater proposing to defer the revenue requirement, net of net variable power cost (NVPC) benefits, from the in-service date of January 2024 until Clearwater was reflected in customer prices, which was March 1, 2025. For the year ended December 31, 2024, PGE deferred the revenue requirement, net of NVPC benefits resulting in a net regulatory liability of $40 million, which began amortizing as a refund to customers on March 1, 2025 over a twelve-month period, as approved in OPUC Order 25-075 issued February 21, 2025. For the period of January 1, 2025 through December 31, 2025, PGE deferred an additional net $13 million regulatory liability, which remains subject to a future regulatory review, representing the deferred revenue requirement that PGE believes is probable of recovery, net of NVPC that is probable of refund to customers under the RAC for that period. The OPUC has significant discretion on overall prudence and in making the final determination of recovery or refund. Any cost disallowance or increased refunds would be recognized as a charge to earnings.

NOTE 8: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2025	2024
Trojan decommissioning activities	$ 208	$ 205
Utility plant	75	80
Non-utility property	29	25
Total asset retirement obligations	312	310
Less: current portion *	13	18
Noncurrent asset retirement obligations	$ 299	$ 292

* Current portion of AROs are classified within Accrued expenses and other current liabilities in the consolidated balance sheets.

Trojan decommissioning activities represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the ISFSI, an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI will store the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2059. In 2025, the Company recorded an increase in the ARO of $2 million due to an increase in expected annual ISFSI operation costs. The Company also recorded accretion of $9 million and a reduction of $8 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the

co-owners $10 million in 2025 for costs incurred in 2024 and $22 million in 2024 for costs incurred in 2023 resulting from USDOE delays in accepting spent nuclear fuel.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is legally required. During 2025, utility AROs decreased by $5 million, with the change comprised of accretion of $3 million, and a reduction of $8 million due to settled liabilities.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties that are currently or previously leased to third parties. Revisions to estimates for non-utility AROs relate to assets that are no longer in service and the offset is charged directly to Depreciation and amortization on the consolidated statements of income in the period in which the revisions are probable and reasonably estimable. Non-utility AROs are not subject to regulatory deferral.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2025	2024	2023
Balance as of beginning of year	$ 310	$ 286	$ 289
Liabilities incurred	—	—	2
Liabilities settled	(13)	(16)	(25)
Accretion expense	13	12	11
Revisions in estimated cash flows	2	28	9
Balance as of end of year	$ 312	$ 310	$ 286

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate NDT in the consolidated balance sheet for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 9: CREDIT FACILITIES

On September 10, 2025, PGE entered into an amendment of its existing revolving credit facility that extended the scheduled expiration into September 2030. As of December 31, 2025, PGE had a $750 million revolving credit facility that provides the Company the ability to expand to $850 million, if needed. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, including as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, three or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. The revolving credit facility contains a provision that requires annual fees based on the Company's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2025, PGE was in compliance with this covenant with a 53.0% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2025, PGE had no commercial paper outstanding.

Under the revolving credit facility, as of December 31, 2025, PGE had no borrowings outstanding and there were no letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $750 million.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

In addition, PGE has four letter of credit facilities that provide a total capacity of $320 million under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, a total of $192 million of letters of credit were outstanding as of December 31, 2025. Outstanding letters of credit are not reflected on the Company's consolidated balance sheets.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2028.

Short-term borrowings under these credit facilities, and related interest rates, are reflected in the following table (dollars in millions):

	Year Ended December 31,		
	2025	2024	2023
Average daily amount of short-term debt outstanding	$ 21	$ 39	$ 63
Weighted daily average interest rate *	4.6%	5.5%	5.5%
Maximum amount outstanding during the year	$ 180	$ 319	$ 225

* Excludes the effect of commitment fees, facility fees, and other financing fees.

NOTE 10: LONG-TERM DEBT AND OTHER FINANCING ARRANGEMENTS

Long-term debt

Long-term debt consists of the following (dollars in millions):

	As of December 31,	
	2025	2024
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.60% in 2025 and 4.52% in 2024, due at various dates through 2059.	$ 4,560	$ 4,250
Unsecured term bank loan	—	170
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	4,679	4,539
Less: Unamortized debt expense	(17)	(15)
Less: Current portion of long-term debt	—	(170)
Long-term debt, net of current portion	$ 4,662	$ 4,354

First Mortgage Bonds—On March 25, 2025, PGE entered into a Bond Purchase Agreement related to the sale of $310 million in FMBs. The Bonds were issued and funded in full on March 25, 2025 and consist of:

- a series, due in 2035, in the amount of $60 million that will bear interest from its issuance date at an annual rate of 5.36%;
- a series, due in 2045, in the amount of $50 million that will bear interest from its issuance date at an annual rate of 5.72%; and
- a series, due in 2055, in the amount of $200 million that will bear interest from its issuance date at an annual rate of 5.84%.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

Term Loan—On November 14, 2024, PGE obtained a 366-day term loan from lenders in the aggregate principal of $300 million under a 366-Day Bridge Credit Agreement. Pursuant to the Agreement, on November 14, 2024, PGE drew a loan from the lenders in the aggregate principal of $220 million. The term loan bore interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 80.0 basis points. The interest rate was subject to adjustment pursuant to the terms of the loan. On December 31, 2024, PGE repaid $50 million of the term loan. On March 31, 2025, the Company repaid another $102 million, and on October 27, 2025 repaid the remaining balance of $68 million, repaying the loan in full.

Pollution Control Revenue Bonds—In March 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal that bear an interest rate of 2.125%, and $21 million aggregate principal that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on the PCRBs.

As of December 31, 2025, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2026	$	—
2027		160
2028		100
2029		200
2030		325
Thereafter		3,894
	$	4,679

Pelton/Round Butte financing arrangement

Under terms of an agreement approved by the OPUC in 2000, PGE had a 66.67% ownership interest in the 455 Megawatt (MW) Pelton/Round Butte hydroelectric project on the Deschutes River (Pelton/Round Butte), with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). In the agreement, the CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte which was exercised in 2022. Under terms of the agreement, the CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, the CTWS' ownership percentage would exceed 50%. PGE remains the operator of the project.

PGE has agreed to purchase 100% of the CTWS' share of the project's output under a power purchase agreement (PPA) through 2040. The exercise of the purchase option in 2022 was evaluated as a sale-leaseback arrangement, and PGE determined that the transaction did not qualify for sale-leaseback accounting. As a result, the transaction is accounted for as a financing arrangement. PGE records the tangible utility asset within Electric utility plant, net on the consolidated balance sheets as if it were the legal owner and recognizes depreciation expense over the estimated useful life. The monthly PPA payments are split between interest expense and a reduction of the principal portion of the financing obligation, which is included in Other noncurrent liabilities. Differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices.

As of December 31, 2025, the future minimum payments on the financing arrangement are as follows (in millions):

Years ending December 31:		
2026	$	5
2027		5
2028		5
2029		5
2030		5
Thereafter		55
Total Payments		80
Less: Imputed Interest		(49)
Present value of minimum payments	$	31

NOTE 11: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, which is closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate.

PGE made $22 million in contributions to the pension plan in 2025, $16 million in 2024, and none in 2023. PGE expects to contribute $27 million to the pension plan in 2026.

PGE executed an annuity contract purchase in January 2025 to settle future benefit obligations for a portion of the defined benefit pension plan. The annuity contract purchase, in combination with elevated lump sum benefit elections throughout 2025, resulted in a $4 million settlement loss, which has been recorded in Miscellaneous income (expense), net on the consolidated statement of income.

Other Postretirement Benefits—PGE offers non-contributory postretirement health and life insurance plans, and provides health reimbursement arrangements (HRAs) to its employees (collectively, "Other Postretirement Benefits" in the following tables). PGE's obligation pursuant to the postretirement health plan is limited by establishing a maximum benefit per employee with any additional cost the responsibility of the employee.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, equity securities, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

Non-Qualified Benefit Plan—The NQBP in the following tables include obligations for a Supplemental Executive Retirement Plan and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also includes pension make-up benefits for employees that participate in the Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide partial funding for the future requirements of these plans. The assets of such trust are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bonds, and equity mutual funds, are classified as equity or trading debt securities and recorded at fair value. The measurement date for the NQBP is December 31. For further information regarding these trust investments, see Note 5, Fair Value of Financial Instruments.

Other NQBP—In addition to the NQBP discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. PGE holds investments in a NQBP trust that are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in PGE's consolidated balance sheets are as follows as of December 31 (in millions):

	2025			2024		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 15	$ 21	$ 36	$ 16	$ 18	$ 34
Non-qualified benefit plan liabilities *	13	57	70	14	60	74

* For the NQBP, excludes the current portion of $2 million in 2025 and in 2024, which are classified in Accrued expenses and other current liabilities in the consolidated balance sheets.

Investment Policy and Asset Allocation—The Finance Committee of the PGE Board of Directors appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for the implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment strategy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities, and other alternative investments. Asset classes are regularly rebalanced to ensure asset allocations remain within prescribed parameters.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
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The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2025		2024	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Growth securities	55%	55%	53%	55%
Liability Hedging Fixed Income securities	45	45	47	45
Total	100	100	100	100
Other Postretirement Benefit Plans:				
Equity securities	40%	39%	40%	38%
Debt securities	60	61	60	62
Total	100	100	100	100
Non-Qualified Benefits Plans:				
Equity securities	1%	1%	1%	2%
Debt securities	2	2	6	5
Insurance contracts	97	97	93	93
Total	100	100	100	100

* The target for the Defined Benefit Pension Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the NQBP, these targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average targets for the Other Postretirement Benefit Plans and NQBP, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Other *	Total
As of December 31, 2025:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 13	$ —	$ —	$ —	$ 13
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	473	473
Private equity funds	—	—	—	1	1
	$ 13	$ —	$ —	$ 479	$ 492
Other Postretirement Benefit Plans assets:					
Equity securities:					
Domestic	—	2	—	—	2
International	5	—	—	—	5
Debt securities—Domestic	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	12	12
Collective trust funds	—	—	—	4	4
	$ 5	$ 7	$ —	$ 16	$ 28
As of December 31, 2024:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 13	$ —	$ —	$ —	$ 13
Investments measured at NAV:					
Money market funds	—	—	—	30	30
Collective trust funds	—	—	—	440	440
Private equity funds	—	—	—	1	1
	$ 13	$ —	$ —	$ 471	$ 484
Other Postretirement Benefit Plans assets:					
Equity securities:					
Domestic	—	2	—	—	2
International	4	—	—	—	4
Debt securities—Domestic government	—	4	—	—	4
Investments measured at NAV:					
Money market funds	—	—	—	11	11
Collective trust funds	—	—	—	4	4
	$ 4	$ 6	$ —	$ 15	$ 25

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 5, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable NAV. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Mutual fund assets included in separately managed accounts are classified as Level 2 securities due to pricing inputs that are directly or indirectly observable in the marketplace.

Debt Securities—Debt security investment funds are classified as Level 2 securities as pricing for underlying securities are determined by evaluating pricing data, such as broker quotes for similar securities, adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, if applicable.

Collective trust funds—Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset-backed securities, are included in commingled trusts or separately managed accounts. The funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds, which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
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The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2025 and 2024. Information related to the Other NQBP is not included in the following tables (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2025	2024	2025	2024	2025	2024
Benefit obligation:						
As of January 1	$ 612	$ 690	$ 37	$ 35	$ 16	$ 18
Service cost	10	10	1	1	—	—
Interest cost	32	33	2	2	1	—
Actuarial (gain) loss	7	(40)	—	1	1	—
Benefits paid from plan assets	(29)	(78)	(2)	(3)	(3)	(2)
Administrative expenses	(3)	(3)	—	—	—	—
Plan settlements	(40)	—	—	—	—	—
Special/contractual termination benefits	—	—	—	1	—	—
As of December 31	$ 589	$ 612	$ 38	$ 37	$ 15	$ 16
Fair value of plan assets:						
As of January 1	$ 484	$ 530	$ 25	$ 23	$ 16	$ 17
Actual return on plan assets	58	19	3	2	(1)	(1)
Company contributions	22	16	2	3	3	2
Benefit payments	(29)	(78)	(2)	(3)	(3)	(2)
Administrative expenses	(3)	(3)	—	—	—	—
Plan settlements	(40)	—	—	—	—	—
As of December 31	$ 492	$ 484	$ 28	$ 25	$ 15	$ 16
Unfunded position as of December 31	$ (97)	$ (128)	$ (10)	$ (12)	$ —	$ —
Accumulated benefit plan obligation as of December 31	$ 551	$ 574	N/A	N/A	$ 15	$ 16
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 15	$ 16
Current liability	—	—	—	(1)	(2)	(2)
Noncurrent liability	(97)	(128)	(10)	(11)	(13)	(14)
Net asset (liability)	$ (97)	$ (128)	$ (10)	$ (12)	$ —	$ —
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (16)	$ (20)	$ (2)	$ —	$ 1	$ —
Net settlement (loss)	(4)	—	—	—	—	—
Amortization of net actuarial gain (loss)	—	—	—	—	(1)	(1)
	$ (20)	$ (20)	$ (2)	$ —	$ —	$ (1)
Amounts included in AOCL: *						
Net actuarial loss (gain)	$ 65	$ 85	$ (5)	$ (3)	$ 6	$ 6
Prior service cost	(1)	(1)	—	—	—	—
	$ 64	$ 84	$ (5)	$ (3)	$ 6	$ 6

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are classified as Regulatory assets or liabilities as future recoverability is expected from retail customers.

Significant actuarial gains (losses) experienced that resulted in changes in projected benefit obligation included the following:

- For the defined benefit pension plan, actuarial gains and losses due to demographic experience, including assumption changes, were a loss of $7 million and a gain of $40 million, and the changes between actual and expected return on plan assets were a gain of $23 million and a loss of $20 million, for the years ended December 31, 2025 and 2024, respectively.
- For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were an immaterial loss and a loss of $1 million, and the changes between actual and expected return on plan assets were a gain of $2 million and a gain of $1 million, for the years ended December 31, 2025 and 2024, respectively.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2025	2024	2023	2025	2024	2023	2025	2024	2023
Service cost	$ 10	$ 10	$ 10	$ 1	$ 1	$ 1	$ —	$ —	$ —
Interest cost on benefit obligation	32	33	37	2	2	2	1	—	1
Expected return on plan assets	(36)	(39)	(43)	(1)	(1)	(1)	—	—	—
Amortization of prior service credit	—	—	(1)	—	—	—	—	—	—
Amortization of net actuarial loss (gain)	—	—	—	—	—	(1)	1	1	1
Settlement loss (gain)	4	—	—	—	—	(1)	—	—	—
Net periodic benefit cost	$ 10	$ 4	$ 3	$ 2	$ 2	$ —	$ 2	$ 1	$ 2

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans is classified as Miscellaneous income, net within Other income, net on the Company's consolidated statements of income. A portion of current period non-service costs attributable to capital projects is recorded as a regulatory asset and amortized to Miscellaneous income, net over time.

The following assumptions were used in determining benefit obligations and net period benefit costs:

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2025	2024	2025	2024	2025	2024
Assumptions used to determine benefit obligations:						
Discount rate	5.56%	5.70%	5.29%	5.59%	5.56%	5.70%
			6.11%	6.11%		
Rate of compensation increase	4.14%	4.08%	4.03%	4.02%	3.96%	3.98%
Assumptions used to determine net periodic benefit cost:						
Discount rate	5.70%	5.13%	5.59%	5.18%	5.70%	5.13%
			6.11%	5.57%		
Rate of compensation increase	4.08%	4.19%	4.02%	4.06%	3.98%	4.01%
Long-term rate of return on plan assets	6.88%	6.88%	4.78%	4.73%	N/A	N/A

As of December 31, 2025, there are no liabilities with sensitivity to health care cost trend rates.

The expected rate of return on plan assets each year is based on the approved asset allocation. A forward looking building blocks approach is used with historical returns, capital markets information and survey information used to support the expected rate of return on plan assets assumption. All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2026	2027	2028	2029	2030	2031 - 2035
Defined benefit pension plan	$ 44	$ 44	$ 44	$ 44	$ 43	$ 219
Other postretirement benefits	4	4	4	5	4	11
Non-qualified benefit plans	2	2	2	2	2	6
Total	$ 50	$ 50	$ 50	$ 51	$ 49	$ 236

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE's defined benefit pension plan, the Company matches employee contributions to the 401(k) Plan up to 7% of the employee's base pay and also contributes 1% of the employee's base pay, whether or not the employee contributes to the 401(k) Plan as a profit share.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company adds an additional 1% of the employee's base salary to their profit share.

For eligible employees who are not covered by PGE's defined benefit pension plan, the Company matches employee contributions up to 6% of the employee's base pay, and also contributes up to 7% of the employee's base pay as a profit share.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $42 million in 2025, $37 million in 2024, and $31 million in 2023.

NOTE 12: INCOME TAXES

Income tax expense/(benefit) consists of the following (in millions):

	Years Ended December 31,		
	2025	2024	2023
Current:			
Federal	$ 3	$ 2	$ 11
State and local	13	12	26
	16	14	37
Deferred:			
Federal	19	(2)	4
State and local	26	25	4
	45	23	8
Investment Tax Credits	(8)	—	—
Income tax expense	$ 53	$ 37	$ 45

The significant differences between the U.S. Federal statutory rate and PGE's Effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,					
	2025		2024		2023	
Income before income taxes	$ 359		$ 350		$ 273	
Federal statutory tax rate	76	21.0%	74	21.0%	57	21.0%
State and local taxes, net of federal tax benefit [1]	30	8.4	28	8.0	25	9.0
Federal tax credits [2]:						
Energy-related tax credits	(48)	(13.3)	(58)	(16.6)	(27)	(10.0)
Research and development tax credits	(1)	(0.3)	(2)	(0.6)	(2)	(0.7)
Other credits	—	—	—	—	—	(0.1)
Nontaxable or Nondeductible Items:						
Executive Compensation [3]	4	1.1	4	1.4	1	0.5
Other	—	—	1	0.2	—	—
Changes in Unrecognized Tax Benefits	—	—	1	0.2	1	0.3
Effect of ratemaking on income tax accounting [4]	(8)	(2.1)	(11)	(2.9)	(10)	(3.6)
Effective tax rate	$ 53	14.8%	$ 37	10.7%	$ 45	16.4%

(1)State taxes in Oregon make up the majority (greater than 50 percent) of the tax effect in this category.

(2)Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities as well as amortization of investment tax credits (ITCs). PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation will end at various dates through 2034. The generation of PTCs from Tucannon River Wind Farm ended in 2024. ITCs are generated on qualifying renewable energy and infrastructure projects placed in service during 2023, 2024, and 2025. In accordance with the deferral method of accounting, ITCs are recorded as a deferred credit when generated and amortized as a reduction of income tax expense over the estimated useful life of the related properties. These energy-related tax credits are presented net of any transfer discounts. Federal tax credits also include all other federal tax credits and related

deferrals. The tax credit deferrals are established to provide the benefit back to customers over a period agreed upon with the OPUC.
(3)Under IRC Section 162(m), the tax deduction for compensation paid to certain executive officers is limited to $1 million per year.
(4)The effect of ratemaking on income tax accounting primarily reflects excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act. The majority of excess deferred income tax is subject to Internal Revenue Service normalization rules and will be reversed over the remaining regulatory life of the assets using the average rate assumption method.

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31,	
	2025	2024
Deferred income tax assets:		
Employee benefits	$ 79	$ 89
Regulatory liabilities	21	28
Tax credits, net of transfer discount	61	69
Deferred investment tax credits	73	14
Price risk management	50	51
Total deferred income tax assets	284	251
Deferred income tax liabilities:		
Depreciation and amortization	711	633
Regulatory assets	156	169
Other	18	13
Total deferred income tax liabilities	885	815
Deferred income tax liability, net	$ 601	$ 564

As of December 31, 2025, PGE has federal credit carryforwards of $69 million. These credits primarily consist of PTCs, which will expire at various dates through 2045. In determining the need for a valuation allowance, PGE considered anticipated proceeds from the sale of tax credits. However, PGE believes it is more likely than not that its deferred income tax assets as of December 31, 2025 and 2024 will be realized. Accordingly, no material valuation allowance has been recorded. As of December 31, 2025, and 2024, PGE had no material unrecognized tax benefits.

On April 17, 2024, PGE received approval from the OPUC to transfer 2024 and 2025 PTCs and record any difference between the full value and the discounted value as a deferred regulatory asset. On August 20, 2025 and December 15, 2025, PGE received approval from the OPUC to transfer 2025 ITCs and return the net proceeds from the sale to PGE customers. PGE transferred tax credits, net of discounts, of $179 million and $112 million for cash proceeds in 2025 and 2024, respectively. The 2025 proceeds included $37 million from PTC sales and $142 million from ITC sales, net of discounts.

PGE and its subsidiaries file a consolidated federal income tax return. The Company also files income tax returns in the states of Oregon, California, and Montana, and in certain local jurisdictions. The Company files in other states to maintain compliance with remote worker rules and regulations. These additional state filings are not significant to the consolidated financial statements. The Internal Revenue Service has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

Supplemental cash flow information related to cash paid for income taxes consists of the following (in millions):

	Years Ended December 31,		
	2025	2024	2023
Cash paid (received) for income taxes, net:			
Federal			
Federal income taxes paid	$ 4	$ 4	$ 10
Tax credit sales	(179)	(112)	(23)
State and local			
Oregon	12	17	21
Other	1	1	4

NOTE 13: EQUITY-BASED PLANS

At-the-Market Offering Program

In July 2024, PGE entered into an equity distribution agreement under which it could sell up to $400 million of its common stock through at-the-market offering programs. The Company entered into forward sale agreements for 5,756,432 shares and 1,420,049 shares in 2025 and 2024, respectively. In 2024, the Company issued 1,066,549 shares pursuant to the forward sale agreements and received net proceeds of $50 million. During 2025, the Company issued 5,919,618 shares pursuant to the forward sale agreements and received net proceeds of $250 million. The Company could have physically settled the remaining amount by delivering 190,314 shares in exchange for cash of $8 million as of December 31, 2025. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

Prior to settlement, the potentially issuable shares pursuant to the agreements will be considered in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the agreements less the number of shares that could be purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period). Share dilution occurs when the average market price of PGE's stock during the reporting period is higher than the average forward sale price during the reporting period. As of the year ended December 31, 2025, an incremental 5,025 shares were included in the calculation of diluted EPS related to the securities under the agreements. For additional information concerning the Company's diluted earnings per share, see Note 15, Earnings Per Share.

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 1,125,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock or 1,500 shares (based on fair value on the purchase date), whichever is less. Two six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2025, there were 506,969 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the

Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2025, there were 2,451,588 shares available for future issuance pursuant to the DRIP.

NOTE 14: STOCK-BASED COMPENSATION

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective April 21, 2023 (the Plan), the Company may grant a variety of equity-based awards, including RSUs with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs), to non-employee directors, officers, or certain key employees. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Nonvested units as of December 31, 2022	579,461	$ 49.23
Granted	421,788	47.82
Forfeited	(57,566)	48.03
Vested	(297,986)	52.45
Nonvested units as of December 31, 2023	645,697	47.57
Granted	478,509	41.02
Forfeited	(20,774)	45.32
Vested	(306,639)	44.76
Nonvested units as of December 31, 2024	796,793	44.78
Granted	582,444	41.68
Forfeited	(39,944)	42.48
Vested	(364,659)	47.31
Nonvested units as of December 31, 2025	974,634	42.58

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 779,123 shares remain available for future issuance as of December 31, 2025.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to shareholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in shares of PGE common stock valued either at the closing stock price on the vesting date (for performance-based RSUs) or dividend payment date (for all other grants).

Time-based RSUs generally vest over a period of up to three years from the grant date. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was $10 million for the year ended December 31, 2025, $8 million for 2024, and $9 million for 2023.

Performance-based RSUs vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation, Culture and Talent Committee of PGE's Board of Directors. The number of RSUs that may vest under the grants is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity (ROE); ii) average EPS growth; and iii) average megawatts of forecast energy from clean or certain low-carbon emitting resources added to PGE's energy supply portfolio—and relative total shareholder return (TSR) as a modifier to the total of the three equally-weighted metrics for 2023 and 2024 grants. For 2025 grants, ROE is replaced with TSR as one of the three equally-weighted metrics, and there is no modifier. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 200% of the RSUs granted.

For return on equity, average EPS growth, and carbon reduction metrics of the performance-based RSUs, fair value is measured based on the NYSE closing price of PGE common stock on the date of grant. For the TSR portion of the performance-based RSUs, fair value is determined using a Monte Carlo simulation with the following weighted average assumptions:

	2025		2024		2023	
Risk-free interest rate	4.4%		4.3%		4.2%	
Expected term (in years)	2.9		2.9		2.9	
Volatility	15.5% —	65.8%	12.4% —	53.2%	21.8% —	31.5%

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 98.40%, 115.07%, and 81.65% of awarded performance-based RSUs for the respective 2025, 2024, and 2023 grants, with an estimated 5% forfeiture rate on the grant date.

The total value of performance-based RSUs vested was $8 million for the year ended December 31, 2025, $6 million for 2024, and $7 million for 2023.

Stock-based compensation, included in Administrative and other expense in the consolidated statements of income, was $16 million for the year ended December 31, 2025, $24 million for 2024, and $17 million in 2023. Such amounts differ from those reported in the consolidated statements of shareholders' equity for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other expenses in the consolidated statements of income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to shareholders' equity of $4 million in 2025, 2024 and 2023.

As of December 31, 2025, unrecognized stock-based compensation expense was $9 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

NOTE 15: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; ii) contingently issuable time-based and performance-based restricted stock units, along with associated DERs; and iii) shares issuable pursuant to the at-the-market offering program. See Note 13, Equity-based Plans, for additional information on the at-the-market offering program and the resulting impact on earnings per share. Unvested performance-based restricted stock units and associated DERs are included in dilutive potential common shares only after the performance criteria have been met. Anti-dilutive stock awards are excluded from the calculation of diluted earnings per common share.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computations. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Years Ended December 31,		
	2025	2024	2023
Weighted average common shares outstanding—basic	110,471	103,946	97,760
Dilutive potential common shares	268	213	192
Weighted average common shares outstanding—diluted	110,739	104,159	97,952

NOTE 16: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2025, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2026	2027	2028	2029	2030	Thereafter	Total
Capital and other purchase commitments	$ 414	$ 136	$ 24	$ 13	$ 1	$ 40	$ 628
Purchased power and fuel:							
Electricity purchases	504	400	395	389	324	2,888	4,900
Capacity contracts	218	128	129	130	125	618	1,348
Public utility districts	10	9	7	1	1	13	41
Natural gas	88	74	36	30	30	161	419
Coal and transportation	38	38	38	38	—	—	152
Total	$ 1,272	$ 785	$ 629	$ 601	$ 481	$ 3,720	$ 7,488

Capital and other purchase commitments—Certain commitments have been made for 2026 and beyond that include those related to hydro licenses, upgrades to generation, distribution, transmission and energy storage facilities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Subsequent to December 31, 2025, PGE has entered into agreements to construct two solar and battery hybrid projects for a total of 615 MW. These projects are not included in the table above and are summarized as follows:

- Biglow Optimization—PGE entered into an agreement to construct a 125 MW solar facility and a 125 MW BESS in Sherman County, Oregon. PGE will own the resource with an investment of approximately $540 million, excluding AFUDC. The project has an estimated commercial operation date at the end of 2027.
- Wheatridge Expansion—PGE and NextEra Energy, Inc. entered into agreements to construct a 240 MW solar facility and a 125 MW BESS facility, located in Morrow County, Oregon. PGE will own 110 MW of solar and 65 MW of BESS production capacity with an investment of approximately $490 million, excluding AFUDC. NextEra Energy, Inc. which operates the facility, owns the remaining 130 MW of solar and 60 MW of BESS production capacity and sells their portion of the output to PGE under a 30-year PPA. The project has an estimated commercial operation date at the end of 2027.

Electricity purchases and Capacity contracts—PGE has PPAs with counterparties, which expire at varying dates through 2053, and power capacity contracts through 2051. Expenses associated with these commitments are recorded in Purchased power and fuel on the Company's consolidated statements of income.

PGE has evaluated its long-term PPAs under variable interest entity accounting guidance. The Company has concluded that it either has no variable interest in the PPAs or, where variable interests exist, PGE is not the primary beneficiary. As a result, consolidation of these entities is not required. This determination is based on PGE lacking both control over significant activities and obligation to absorb losses or receive benefits from the entities' performance. PGE's financial exposure in these PPAs is limited to capacity and energy payments, which are recovered through the AUT and are subject to the PCAM as detailed in Note 2.

Public utility districts—PGE has long-term PPAs with certain public utility districts (PUDs) in the state of Washington:

- Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and
- Douglas County PUD for the Wells Hydroelectric Project.

Under one of the Grant County agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether they are operable or not. Under one of the Douglas County agreements, the Company is required to make monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas County's loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

Selected information regarding these projects is summarized as follows (dollars in millions):

	Capacity Charges and Revenue Bonds as of December 31, 2025	PGE's Average Share as of December 31, 2025		Contract Expiration	Total PGE Contract Costs		
		Output	Capacity (in MW)		2025	2024	2023
Priest Rapids and Wanapum	$ 1,584	8.6%	163	2052	$ 67	$ 75	$ 77
Wells	200	3.5%	25	2028	10	11	11

The agreements for Priest Rapids and Wanapum provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be responsible for a pro-rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax-exempt status of any of the public utility district's outstanding debt for the portion of the project that benefits tax-exempt purchasers.

Natural gas—PGE has contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities.

Coal—The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generating plant (Colstrip) that expires in December 2029.

Guarantees

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation

under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. In connection with the agreement to transfer certain tax credits generated in 2023 through 2025, PGE provided indemnification against the buyer's losses related to a failure to satisfy the PTC and ITC qualification or transferability requirements under the Internal Revenue Code, but not due to the action or legal tax status of the buyer or a change in tax law. As of December 31, 2025, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

NOTE 17: LEASES

PGE determines if an arrangement is a lease at commencement and whether the arrangement is classified as an operating or finance lease. At commencement of the lease, PGE records a right-of-use (ROU) asset and lease liability in the consolidated balance sheets based on the present value of lease payments over the term of the arrangement. ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent PGE's obligation to make lease payments arising from the lease. If the implicit rate is not readily determinable in the contract, PGE uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Contract terms may include options to extend or terminate the lease, and, when the Company deems it is reasonably certain that PGE will exercise that option, it is included in the ROU asset and lease liability.

Operating leases reflect lease expense on a straight-line basis, while finance leases result in the separate presentation of interest expense on the lease liability and amortization expense of the ROU asset. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

PGE does not record leases with a term of 12-months or less in the consolidated balance sheets. Total short-term lease costs as of December 31, 2025 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

The Company's leases relate primarily to the use of land, support facilities, gas storage, energy storage equipment, and PPAs that rely on identified plant. Variable payments are generally related to gas storage and PPAs for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

The components of lease cost were as follows (in millions):

	2025	2024
Operating lease cost	$ 26	$ 2
Finance lease cost:		
Amortization of right-of-use assets	$ 14	$ 14
Interest on lease liabilities	14	14
Total finance lease cost	$ 28	$ 28
Variable lease cost	$ 22	$ 28

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Supplemental information related to amounts and presentation of leases in the consolidated balance sheets is presented below (in millions):

	Balance Sheet Classification	As of December 31, 2025	2024
Operating Leases:			
Operating lease right-of-use assets	Other noncurrent assets	$ 303	$ 312
Current liabilities	Accrued expenses and other current liabilities	$ 26	$ 26
Noncurrent liabilities	Other noncurrent liabilities	277	286
Total operating lease liabilities *		$ 303	$ 312
Finance Leases:			
Finance lease right-of-use assets	Electric utility plant, net	$ 262	$ 276
Current liabilities	Current portion of finance lease obligations	$ 27	$ 27
Noncurrent liabilities	Finance lease obligations, net of current portion	263	276
Total finance lease liabilities *		$ 290	$ 303

* Included in lease liabilities are $577 million and $599 million related to purchased power and storage contracts for the years ended December 31, 2025 and 2024, respectively. These agreements include hydro and natural gas generation PPAs, gas storage, and battery storage, all of which are included within the Company's AUT and PCAM regulatory mechanisms.

Lease term and discount rates were as follows:

	December 31, 2025	December 31, 2024
Weighted Average Remaining Lease Term (in years)		
Operating leases	21	22
Finance leases	19	20
Weighted Average Discount Rate		
Operating leases	5.8%	5.8%
Finance leases	4.8%	4.8%

PGE's gas storage finance lease contains five 10-year renewal periods which have not been included in the finance lease obligation.

As of December 31, 2025, maturities of lease liabilities were as follows (in millions):

	Operating Leases		Finance Leases	
	PPA*	Other	PPA*	Other
2026	$ 25	$ 1	$ 27	$ —
2027	25	1	27	—
2028	25	1	26	—
2029	25	1	26	—
2030	25	1	26	—
Thereafter	349	39	304	—
Total lease payments	474	44	436	—
Less imputed interest	(187)	(28)	(146)	—
Total	$ 287	$ 16	$ 290	$ —

* These agreements include hydro and natural gas generation PPAs, gas storage, and battery storage contracts, all of which are included within the Company's AUT and PCAM regulatory mechanisms.

Supplemental cash flow information related to leases for the years indicated was as follows (in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows used in operating leases	$ 26	$ 3	$ 4
Operating cash flows used in finance leases	14	14	15
Financing cash flows used in finance leases	14	6	6
Right-of-use assets obtained in leasing arrangements:			
Operating leases	$ —	$ 295	$ —

Battery storage agreements—PGE has entered into three battery storage PPAs subsequent to December 31, 2025 that are expected to be accounted for as leases upon commencement. These projects are summarized as follows:

- on January 9, 2026 PGE entered into an agreement with an expected lease commencement date in December 2027 and a term of 20 years, pending OPUC approval of a waiver filing. The expected total fixed contract consideration will approximate $612 million over the lease term;
- on February 15, 2026, PGE entered into an agreement with an expected lease commencement date in December 2027 and a term of 30 years, subject to approvals. The expected total fixed contract consideration will approximate $331 million over the lease term; and
- on February 15, 2026, PGE entered into an agreement with an expected lease commencement date in June 2028 and a term of 20 years, pending OPUC approval of a waiver filing. The expected total fixed contract consideration will approximate $636 million over the lease term.

NOTE 18: JOINTLY-OWNED PLANT

As of December 31, 2025, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation [1]	Construction Work In Progress
Colstrip - Generation	20%	1986	$ 512	$ 501	$ 3
Colstrip-Transmission	Various (2)	1986	74	45	1
Pelton/Round Butte	50.01%	1958 / 1964	242	81	10
Total			$ 828	$ 627	$ 14

(1) Excludes AROs and accumulated asset retirement removal costs.

(2) 14% of the 2,260 MW transmission facilities between the Colstrip switchyard to the Broadview switchyard, near Billings, Montana, and 16% of the 1,930 MW transmission facilities between the Broadview switchyard and the interconnection point with Bonneville Power Administration's transmission system near Townsend, Montana.

Under the respective joint operating agreements for the facilities, each participating owner is responsible for financing its share of capital and operating expenses. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the consolidated statements of income.

NOTE 19: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) that began in 1997 of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site. PGE has been included among more than one hundred Potentially Responsible Parties (PRPs) as it historically owned or operated property near the river.

A Portland Harbor site remedial investigation was completed pursuant to an agreement between the EPA and several PRPs known as the Lower Willamette Group (LWG), which did not include PGE. The LWG funded the remedial investigation and feasibility study and stated that it had incurred $115 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs, as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued in 2017. The ROD outlined the EPA's selected remediation plan for clean-up of Portland

Harbor that had an undiscounted estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs. Remediation construction costs were estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. Stakeholders have raised concerns that the EPA's cost estimates are understated, and PGE estimates undiscounted total remediation costs for Portland Harbor per the ROD could range from $1.9 billion to $3.5 billion. The EPA acknowledged the estimated costs were based on data that was outdated and that pre-remedial design sampling was necessary to gather updated baseline data to better refine the remedial design and estimated cost.

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of Portland Harbor have improved substantially with the passage of time. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The Company anticipates that remedial design costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy. The entirety of Portland Harbor continues under an active engineering design phase.

PGE continues to participate in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including conclusion of remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor.

In November 2024, the EPA issued a Special Notice Letter (SNL) to 60 entities, including PGE, with requirements and deadlines that may ultimately lead to litigation, in relation to Portland Harbor. By letter dated May 30, 2025, PGE responded in coordination with other SNL recipients, as recommended by the EPA. Formal negotiations are anticipated to take approximately two years, concluding in fall 2026 and no later than March 2027, according to the EPA.

Based on the above facts and remaining uncertainties in the voluntary allocation process, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that would represent PGE's portion of the liability to clean-up Portland Harbor. However, the Company may obtain sufficient information, prior to the final determination of allocation percentages among PRPs, to develop a reasonable estimate, or range, of its potential liability that would require recording of the estimate, or low end of the range. The Company's liability related to the cost of remediating Portland Harbor could be material to PGE's financial position.

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, and the Nez Perce Tribe.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also

compensate the trustees for costs incurred in assessing the damages. PGE's portion of NRD liabilities related to Portland Harbor are immaterial.

The impact of costs related to EPA and NRD liabilities on the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) mechanism. As approved by the OPUC, the PHERA allows the Company to defer estimated liabilities and recover prudently incurred environmental expenditures related to Portland Harbor through a combination of third-party proceeds, including but not limited to insurance recoveries, and, if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent GRC. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company plans to seek recovery of any costs resulting from EPA's determination of liability for Portland Harbor through application of the PHERA. At this time, PGE is not recovering any Portland Harbor cost from the PHERA through customer prices.

Colstrip-Related Matters

The Company has a 20% ownership interest in Colstrip, which is located in the state of Montana and operated by one of the co-owners, Talen Montana, LLC. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation Agreement and other matters. In 2021, an arbitration process was initiated by co-owner, NorthWestern Corporation, against all other co-owners of Colstrip to address such business disagreements and to determine whether co-owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or, alternatively, whether unanimous consent is required. The parties have agreed to stay the arbitration proceedings indefinitely. PGE cannot predict the ultimate outcome of this matter.

Wrongful Death Claims

In September 2025, PGE received a complaint filed in Multnomah County Circuit Court on behalf of the estates of three members of the public and their relatives, with regard to three fatalities that occurred during the January 2024 storm and severe winter weather event. The lawsuit seeks a total of $375 million related to their deaths and surviving family members' claims. Business entities that own and operate an apartment complex, along with a nearby property owner, are also named as defendants. At this time, as the case is in its early stages, PGE is unable to estimate a range of any reasonably possible loss. The Company denies liability and plans to defend its case.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such known matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

NOTE 20: SEGMENT INFORMATION

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity. The Company participates in wholesale markets by purchasing and selling electricity and natural gas in an effort to meet the needs of, and obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory in the State of Oregon.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, continued

The Company has identified one operating and reportable segment and defines its segment on the basis of the way in which internally reported financial information is regularly reviewed by the chief operating decision maker (CODM) to analyze financial performance, make decisions, and allocate resources. The Company's CODM is the President and Chief Executive Officer.

The Company's CODM assesses the segment's performance by using Consolidated Net Income. The CODM uses Consolidated Net Income predominantly as a key input to earnings per share and return on equity, which is an important metric for investors, regulators and is also tied to employee compensation.

The table below provides information about the Company's single business segment, including significant segment expenses, and includes reconciliation to Consolidated Net Income (dollars in millions):

	Years Ended December 31,		
	2025	2024	2023
Total revenues	$ 3,576	$ 3,440	$ 2,923
Operating expenses:			
Purchased power and fuel	1,411	1,418	1,190
Operating and maintenance expense:			
Generation, transmission and distribution	450	436	374
Administrative and other	392	403	341
Total operating and maintenance expense	842	839	715
Depreciation and amortization	578	496	458
Taxes other than income taxes	190	175	164
Total operating expenses	3,021	2,928	2,527
Income from operations	555	512	396
Interest expense, net:			
Interest expense	243	226	186
Allowance for borrowed funds used during construction	11	15	13
Total interest expense, net	232	211	173
Other income, net:	36	49	50
Income before income taxes	359	350	273
Income tax expense	53	37	45
Consolidated Net income	$ 306	$ 313	$ 228

Certain additional financial information relating to the Company's single business segment was as follows (dollars in millions):

	Years Ended December 31,		
	2025	2024	2023
Total assets	$ 13,230	$ 12,544	$ 11,208
Capital expenditures	(1,189)	(1,268)	(1,358)
Equity method investments	19	13	9

NOTE 21: SUBSEQUENT EVENTS

On February 15, 2026, PGE, through a newly formed, wholly owned subsidiary, entered into an Asset Purchase and Service Area Transfer Agreement (the "Agreement") with PacifiCorp, an indirect subsidiary of Berkshire Hathaway Energy Company, to acquire select portions of PacifiCorp's Washington state regulated utility retail business. Under the Agreement, PGE would acquire certain assets and liabilities related to generation, transmission, and distribution business to serve the related service area comprised of approximately 140,000 customers. The stated purchase price is $1.9 billion in cash, subject to customary adjustments, including adjustments for net working capital, regulatory assets and liabilities, assumed liabilities, and capital expenditures at closing.

The acquisition is supported by a fully committed bridge facility with Barclays Bank PLC and JPMorgan Chase Bank, N.A. for $1.9 billion. The Company expects to permanently finance the transaction through a balanced mix of debt, equity, and its minority investment partner, Manulife Infrastructure Fund III L.P. and its affiliates including John Hancock Life Insurance Company (USA) ("Manulife"). In connection with the financing plan, PGE expects equity commitments from Manulife to finance up to $600 million of the purchase. Assuming the closing of the transactions contemplated by the Agreement and the consummation of the financing transactions, Manulife will be the Company's joint venture partner in the business. PGE would remain majority owner and sole operator.

The Agreement also provides for certain termination rights, and under certain specified circumstances, the Company may be required to pay PacifiCorp a termination fee of $35 million. The transaction is expected to consummate twelve months after submission of regulatory filings, subject to customary closing conditions and regulatory approvals, including under the Hart-Scott-Rodino Act, Section 203 of the Federal Power Act from the FERC, the Washington Utilities and Transportation Commission ("WUTC"), the OPUC, the Idaho Public Utilities Commission ("IPUC"), the Public Service Commission of Utah ("UPSC"), the Public Utilities Commission of the State of California ("CPUC") and the Public Service Commission of Wyoming ("WPSC"), and certain other federal and state regulatory approvals.

The transaction is expected to be accounted for as a business combination pursuant to ASC 805, Business Combinations, using the acquisition method of accounting and in which PGE would record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent that the consideration transferred is greater than the fair value of the net assets acquired, goodwill will be recorded.

Through December 31, 2025 and the date of filing, fees incurred as a part of the acquisition have been immaterial.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a)Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective.

(b)Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2025, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2025, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2025.

(c)Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

Rule 10b5-1 Trading Arrangements

PGE has adopted an insider trading policy that governs the purchase, sale, and/or other dispositions of Company securities by its directors, officers, and employees that it believes is reasonably designed to promote compliance with insider trading laws, rules, and regulations and New York Stock Exchange listing standards. A copy of the Insider Trading Policy is included as Exhibit 19.1 to this report.

During the three months ended December 31, 2025, the following directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(c) of Regulation S-K:

Name (Title)	Action Taken (Date of Action)	Type of Trading Arrangement	Duration of Trading Arrangement	Aggregate Number of Securities to be Purchased or Sold
Benjamin Felton (Executive Vice President Chief Operating Officer)	Adoption (November 5, 2025)	Rule 10b5-1 trading arrangement	Until February 26, 2027, or such earlier date upon which all transactions are completed or expire without execution	Up to 9,938 shares of common stock

ITEM 9C. DISCLOSURES REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Certain information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Corporate Governance" and "Item 1: Election of Directors" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the United States Securities and Exchange Commission (SEC) in connection with the Annual Meeting of Shareholders. Information regarding executive officers of Portland General Electric Company may be found in Part I, Item 1. Business of this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Item 1: Election of Directors —Director Compensation," "Item 1: Election of Directors—Board Committees—Compensation, Culture and Talent Committee—Compensation, Culture and Talent Committee Interlocks," "Compensation, Culture and Talent Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" [1]in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a)Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b)Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1).
3.2*	Twelfth Amended and Restated Bylaws of Portland General Electric Company (Form 10-Q filed October 27, 2023, Exhibit 3.2).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1).
4.4*	Seventy-fifth Supplemental Indenture, dated April 1, 2019, between the Company and Wells Fargo Bank, National Association, as trustee (Form 8-K filed April 15, 2019, Exhibit 4.1).
4.5*	Description of Securities (Form 10-K filed February 15, 2019, Exhibit 4.6).
(10)	**Material Contracts**
10.1*	First Amendment to Credit Agreement, dated as of September 9, 2022, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders. (8-K filed September 9, 2022, Exhibit 10.1).
10.2*	Second Amendment to Credit Agreement, dated as of August 18, 2023, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (8-K filed August 22, 2023, Exhibit 10.1).
10.3*	Third Amendment to Credit Agreement, dated as of September 10, 2024, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 14, 2025, Exhibit 10.3).

Exhibit Number	Description
10.4*	Fourth Amendment to Credit Agreement, dated September 10, 2025, among Portland General Electric Company, the Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-Q filed October 31, 2025, Exhibit 10.1).
10.5*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.6*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.7*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.8*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.9*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.10*	Form of Directors' Restricted Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.18).+
10.11*	Portland General Electric Company Amended and Restated Severance Pay Plan for Executive Employees (the "Amended Plan"), effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.1).+
10.12*	Portland General Electric Company Annual Cash Incentive Plan as amended and restated effective July 27, 2021 (Form 10-Q filed July 30, 2021, Exhibit 10.2).+
10.13*	Portland General Electric Company Stock Incentive Plan as amended and restated effective April 21, 2023 (Form DEF 14A filed March 10 2023, Appendix A).+
10.14*	Form of Officers' and Key Employees' Performance Stock Unit Agreement. (Form 10-K filed February 17, 2022, Exhibit 10.15).+
10.15*	Form of Officers' and Key Employees' Restricted Stock Unit Agreement. (Form 10-K filed February 17, 2022, Exhibit 10.16).+
10.16*	Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 10-Q filed October 27, 2023, Exhibit 10.1).+
(19)	**Insider Trading Policy**
19.1*	Portland General Electric Company Insider Trading Policy effective December 19, 2024 (Form 10-K filed February 20, 2024, Exhibit 19.1).
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(97)	**Policy Relating to Recovery of Erroneously Awarded Compensation**
97.1*	Portland General Electric Company Amended and Restated Incentive Compensation Clawback and Cancellation Policy. (Form 10-K filed February 20, 2024, Exhibit 97.1)
(101)	**Interactive Data File**
101.INS	Inline XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema With Embedded Linkbase Documents.
104	The cover page for the Company's Annual Report on Form 10-K has been formatted in Inline XBRL and contained in Exhibit 101

* Incorporated by reference as indicated.
+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 17, 2026.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE
Maria M. Pope
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 17, 2026.

Signature	Title
/s/ MARIA M. POPE **Maria M. Pope**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JOSEPH R. TRPIK **Joseph R. Trpik**	*Senior Vice President, Finance and Chief Financial Officer* (principal financial and accounting officer)
/s/ MARIE OH HUBER **Marie Oh Huber**	*Director*
/s/ KATHRYN J. JACKSON **Kathryn J. Jackson**	*Director*
/s/ RENÉE J. JAMES **Renée J. James**	*Director*
/s/ MICHAEL A. LEWIS **Michael A. Lewis**	*Director*
/s/ MICHAEL H. MILLEGAN **Michael H. Millegan**	*Director*
/s/ JOHN O'LEARY **John O'Leary**	*Director*
/s/ PATRICIA S. PINEDA **Patricia S. Pineda**	*Director*
/s/ JAMES P. TORGERSON **James P. Torgerson**	*Director*