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

FORM 10-Q

[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended **June 30, 2018**

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: **001-5532-99**

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)

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. [x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files).
[x] Yes [ ] No

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

Large accelerated filer [x]	Accelerated filer [ ]
Non-accelerated filer [ ]	(Do not check if a smaller reporting company)
	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 standard provided pursuant to Section 13(a) of the Exchange Act. [ ]

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

Number of shares of common stock outstanding as of July 17, 2018 is 89,238,445 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2018

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DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
AUT	Annual Power Cost Update Tariff
Boardman	Boardman coal-fired generating plant
Carty	Carty natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
CWIP	Construction work-in-progress
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
GRC	General Rate Case
IRP	Integrated Resource Plan
Moody’s	Moody’s Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
TCJA	United States Tax Cuts and Jobs Act
Trojan	Trojan nuclear power plant

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
Revenues:				
Revenues, net	$ 449	$ 449	$ 944	$ 979
Alternative revenue programs, net of amortization	—	—	(2)	—
Total revenues	449	449	942	979
Operating expenses:				
Purchased power and fuel	104	118	234	259
Generation, transmission and distribution	71	81	140	162
Administrative and other	70	64	139	131
Depreciation and amortization	93	86	185	170
Taxes other than income taxes	31	31	64	64
Total operating expenses	369	380	762	786
Income from operations	**80**	**69**	**180**	**193**
Interest expense, net	31	30	62	60
Other income:				
Allowance for equity funds used during construction	2	3	6	5
Miscellaneous income (expense), net	1	—	—	—
Other income, net	3	3	6	5
Income before income tax expense	**52**	**42**	**124**	**138**
Income tax expense	6	10	14	33
Net income	**46**	**32**	**110**	**105**
Other comprehensive income	—	1	—	—
Comprehensive income	$ 46	$ 33	$ 110	$ 105
Weighted-average shares outstanding—basic and diluted (in thousands)	89,215	89,063	89,188	89,033
Earnings per share—basic and diluted	$ 0.51	$ 0.36	$ 1.23	$ 1.18
Dividends declared per common share	$ 0.3625	$ 0.3400	$ 0.7025	$ 0.6600

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(Unaudited)

	June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 48	$ 39
Accounts receivable, net	162	168
Unbilled revenues	86	106
Inventories	85	78
Regulatory assets—current	56	62
Other current assets	56	73
Total current assets	**493**	**526**
Electric utility plant, net	6,840	6,741
Regulatory assets—noncurrent	441	438
Nuclear decommissioning trust	42	42
Non-qualified benefit plan trust	38	37
Other noncurrent assets	55	54
Total assets	**$ 7,909**	**$ 7,838**

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS, continued
(Dollars in millions)
(Unaudited)

	June 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 103	$ 132
Liabilities from price risk management activities—current	51	59
Current portion of long-term debt	300	—
Accrued expenses and other current liabilities	225	241
Total current liabilities	**679**	**432**
Long-term debt, net of current portion	2,126	2,426
Regulatory liabilities—noncurrent	1,348	1,288
Deferred income taxes	378	376
Unfunded status of pension and postretirement plans	280	284
Liabilities from price risk management activities—noncurrent	136	151
Asset retirement obligations	192	167
Non-qualified benefit plan liabilities	107	106
Other noncurrent liabilities	198	192
Total liabilities	**5,444**	**5,422**
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of June 30, 2018 and December 31, 2017	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,238,206 and 89,114,265 shares issued and outstanding as of June 30, 2018 and December 31, 2017, respectively	1,208	1,207
Accumulated other comprehensive loss	(8)	(8)
Retained earnings	1,265	1,217
Total equity	**2,465**	**2,416**
Total liabilities and equity	**$ 7,909**	**$ 7,838**

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2018	**2017**
Cash flows from operating activities:		
Net income	$ 110	$ 105
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	185	170
Deferred income taxes	6	20
Pension and other postretirement benefits	13	13
Allowance for equity funds used during construction	(6)	(5)
Decoupling mechanism deferrals, net of amortization	2	(15)
Deferral of net benefits due to Tax Reform	25	—
Other non-cash income and expenses, net	4	16
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	26	55
(Increase) in inventories	(7)	—
Decrease in margin deposits, net	4	7
(Decrease) in accounts payable and accrued liabilities	(20)	(29)
Other working capital items, net	13	11
Other, net	(17)	(15)
Net cash provided by operating activities	**338**	**333**
Cash flows from investing activities:		
Capital expenditures	(266)	(245)
Sales of Nuclear decommissioning trust securities	6	11
Purchases of Nuclear decommissioning trust securities	(5)	(9)
Other, net	—	(2)
Net cash used in investing activities	**(265)**	**(245)**
Cash flows from financing activities:		
Dividends paid	(61)	(57)
Other	(3)	(4)
Net cash used in financing activities	**(64)**	**(61)**
Increase in cash and cash equivalents	**9**	**27**
Cash and cash equivalents, beginning of period	**39**	**6**
Cash and cash equivalents, end of period	**$ 48**	**$ 33**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 58	$ 55
Cash paid for income taxes	10	13
Non-cash investing and financing activities:		
Assets obtained under leasing arrangements	12	55

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: BASIS OF PRESENTATION

Nature of Business

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. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail 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's corporate headquarters is located in Portland, Oregon and its approximately four thousand square mile, state-approved service area allocation, located entirely within the State of Oregon, encompasses 51 incorporated cities, of which Portland and Salem are the largest. As of June 30, 2018, PGE served approximately 883 thousand retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the state's population.

Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Certain information and note disclosures normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted pursuant to such regulations, although PGE believes that the disclosures provided are adequate to make the interim information presented not misleading.

The financial information included herein for the six months ended June 30, 2018 and 2017 is unaudited; however, such information reflects all adjustments, consisting of normal recurring adjustments, that are, in the opinion of management, necessary for a fair presentation of the condensed consolidated financial position, condensed consolidated income and comprehensive income, and condensed consolidated cash flows of the Company for these interim periods. The financial information as of December 31, 2017 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2017, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 16, 2018, which should be read in conjunction with such condensed consolidated financial statements.

Comprehensive Income

No material change occurred in Other comprehensive income in the three and six months ended June 30, 2018 and 2017. PGE recorded a net $1 million gain in Other comprehensive income for the three months ended June 30, 2017 due to the combination of changes in compensation retirement benefit liability and amortization, net of taxes of an immaterial amount, and other miscellaneous adjustments.

Use of Estimates

The preparation of condensed consolidated financial statements in accordance with 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 experienced by the Company could differ materially from those estimates.

Certain costs are estimated for the full year and allocated to interim periods based on estimates of operating time expired, benefit received, or activity associated with the interim period; accordingly, such costs may not be reflective of amounts to be recognized for a full year. Due to seasonal fluctuations in electricity sales, as well as the price of wholesale energy and natural gas, interim financial results do not necessarily represent those to be expected for the year.

Recent Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2016-02, *Leases (Topic 842)*, which supersedes the current lease accounting requirements for lessees and lessors within *Topic 840, Leases.* Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of interest expense on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset.

Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The provisions of this pronouncement are effective for calendar year-end, public entities on January 1, 2019. As issued, ASU 2016-02 requires transition under a modified retrospective basis as of the beginning of the earliest comparative period presented; however the Company is monitoring the FASB's decisions regarding potential transition practical expedients that would allow companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. Early adoption is permitted, but the Company does not plan to early adopt. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amends ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. PGE plans to elect this practical expedient. The Company is monitoring utility industry implementation issues that may change existing and future lease classification in areas such as purchase power agreements, pipeline laterals, utility pole attachments, and other utility industry-related arrangements. In conjunction with monitoring industry issues that may impact lease classification, the Company is in the process of evaluating whether it will elect to adopt certain, optional practical expedients included within the standard. Decisions surrounding the election of practical expedients may impact the Company's lease population that is ultimately recorded. As a result, PGE has not yet quantified the estimated financial statement impact, but overall, the Company does expect an increase in the recognition of right-of-use assets and lease liabilities on the Company's consolidated balance sheet.

In February 2018, the FASB issued ASU 2018-02 *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). ASU 2018-02 allows for a reclassification from accumulated other comprehensive income to retained earnings for the stranded tax effects resulting from the Tax Cuts and Jobs Act (the TCJA). The amendments only relate to the reclassification of the income tax effects of the TCJA, and therefore the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. For calendar year-end entities, the update will be effective for annual periods beginning January 1, 2019, and interim periods within those fiscal years. Early adoption of the amendments is permitted, including adoption in any interim period. PGE has determined that ASU 2018-02 will not have a material impact on its financial position and it may early adopt the standard in 2018.

Recently Adopted Accounting Pronouncements

On January 1, 2018, PGE adopted ASU 2014-09, *Revenue from Contracts with Customers* (Topic 606), which created Topic 606 and superseded the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. The Company applied the modified retrospective transition method to its revenue contracts not yet completed as of January 1, 2018. As a result, amounts previously recorded prior to January 1, 2018 have not been retrospectively restated and are reported in accordance with historical accounting under Topic 605, while revenues for the three and six months ended June 30, 2018 have been presented under Topic 606.

PGE's transition to the new revenue standard did not result in a material adjustment to opening retained earnings and the Company expects the adoption of the new standard to have an immaterial impact to its results of operations on an ongoing basis. In accordance with the new provisions of Topic 606 PGE has included enhanced quantitative and qualitative disclosures, such as disaggregated revenues by customer class. Adoption of the new standard also resulted in a change to PGE's presentation and classification of its alternative revenue programs, which are predominately comprised of the decoupling mechanism and renewable adjustment clause (RAC). Pursuant to the new standard, such revenues should be presented separately from revenues from contracts with customers as these amounts represent a contract with the regulator and not with customers. As a result, $2 million, net of amortization, primarily related to PGE's decoupling mechanism, has been classified as Alternative revenue programs, net of amortization in the condensed consolidated statements of income and comprehensive income for the six months ended June 30, 2018. There was no material alternative revenue programs activity for the three-month period ended June 30, 2018. If PGE had not applied the new provisions of Topic 606, then PGE would have reported Revenues, net of $449 million and $942 million under Topic 605 for the three and six months ended June 30, 2018, respectively, with the difference attributable to the presentation and classification of alternative revenue programs. For further information regarding changes to the Company's revenue recognition accounting policies, see Note 2, Revenue Recognition.

On January 1, 2018, PGE adopted ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). On a prospective basis, only the service cost component of net periodic pension and postretirement benefit costs is eligible for capitalization to Electric utility plant, net. However, for ratemaking purposes the Company will continue to be allowed to recover its non-service costs related to capital as a component of rate base. Instead of recording such amounts to Electric utility plant, net, the Company will record a Regulatory asset on the condensed consolidated balance sheet that will be amortized in a systematic and rational manner. As of the three and six months ended June 30, 2018, the Company has recorded $1 million and $2 million, respectively, of the non-service costs component of net periodic pension and postretirement benefit costs as a Regulatory asset and estimates this amount will be $3 million for the twelve months ending December 31, 2018. The new pronouncement also requires, on a retrospective basis, that the non-service cost component of net periodic pension and postretirement benefit costs attributable to expense be presented separately from the service cost component and outside the subtotal of income from operations on the condensed consolidated statements of income and comprehensive income. As of the three and six months ended June 30, 2018, the portion of non-service costs attributable to expense is $2 million and $3 million, respectively, classified as Miscellaneous income (expense), net within Other income on the Company's condensed consolidated statements of income and comprehensive income. To conform to the 2018 presentation, PGE has retrospectively reclassified $1 million and $2 million, respectively, of the non-service costs component for the three and six months ended June 30, 2017 from Administrative and other within Operating expenses to Miscellaneous income (expense), net within Other income. The implementation of ASU 2017-07 has had an immaterial impact on PGE's consolidated financial position and consolidated results of operations.

On April 1, 2018, PGE early adopted ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*. The ASU is intended to simplify the application of hedge accounting and provide increased transparency as to the scope and results of hedging programs. The current impact of this adoption is immaterial to PGE's consolidated financial statements as the majority of PGE's price risk management derivatives are related to electric and natural gas commodity price economic hedges. However, PGE periodically enters into interest rate swaps that are designated as cash flow hedges to hedge portions of consolidated interest rate risk associated with anticipated issues of fixed-rate, long-term debt securities. In the event PGE elects to apply hedge accounting to these transactions, PGE will apply the new provisions of this ASU and its related disclosures.

NOTE 2: REVENUE RECOGNITION

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 goods and services provided, are regulated by the Public Utility Commission of Oregon (OPUC) or the Federal Energy Regulatory Commission (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.

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 Note 3, Balance Sheet Components.

Alternative Revenue Programs

Revenues related to PGE's decoupling mechanism and RAC are considered to be earned under alternative revenue programs, in accordance with the new revenue standard. Such revenues are presented separately from revenues from contracts with customers and classified as Alternative revenue programs, net of amortization on the condensed consolidated statement of income and comprehensive income, as these amounts represent a contract with the regulator and not with customers. 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.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

Disaggregated Revenue

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

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Retail:		
Residential	$ 207	$ 475
Commercial	162	313
Industrial	39	83
Direct access customers	13	23
Subtotal	421	894
Alternative revenue programs, net of amortization	—	(2)
Other accrued (deferred) revenues, net[(1)]	(10)	(27)
Total retail revenues	411	865
Wholesale revenues[(2)]	24	52
Other operating revenues	14	25
Total revenues	$ 449	$ 942

(1) Includes a regulatory liability deferral of $10 million and $25 million for the three and six months ended June 30, 2018, respectively, related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under the TCJA. For further information, see Note 10, Income Taxes.
(2) Wholesale revenues includes $4 million and $6 million related to electricity commodity contract derivative settlements for the three and six months ended June 30, 2018, respectively. Price risk management derivative activities are included within total revenues but do not represent revenues from contracts with customers pursuant to Topic 606. For further information, see Note 5, Risk Management.

Retail Revenues

The Company’s primary revenue source is generated through the sale of electricity to customers based on 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 season and summer cooling season. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. 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 little impact on this customer class.

In accordance with state regulations, PGE’s retail customer prices are based on the Company’s cost of service and are determined through general rate case proceedings and various tariff filings with the OPUC. Additionally, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options for residential and small commercial customers.

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 has not yet been billed to customers. This amount, which is classified as Unbilled revenues in the Company’s condensed consolidated balance sheets, is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current customer prices.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct goods 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 to transfer each distinct delivery of electricity in the series to the customer.

Pursuant to regulation by the OPUC, PGE is mandated to maintain several tariff schedules to collect funds from customers associated with activities for the benefit of 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 are not reflected in Revenues, net within the condensed consolidated statements of income and comprehensive income.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand.

The majority of PGE's wholesale electricity sales is to utilities and power marketers, is predominantly short-term, and consists of a single performance obligation 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 resales, 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. PGE generally determines standalone selling prices based on the prices charged to customers.

Practical Expedients and Exemptions

PGE does not disclose the value of unsatisfied performance obligations for: i) contracts with an original expected length of one year or less; and ii) contracts for which the Company recognizes revenue at the amount to which it has the right to invoice for goods delivered or services performed.

NOTE 3: BALANCE SHEET COMPONENTS

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.

Other Current Assets

Other current assets consist of the following (in millions):

	June 30, 2018	December 31, 2017
Prepaid expenses	$ 38	$ 50
Assets from price risk management activities	3	6
Margin deposits	7	11
Other	8	6
Other current assets	$ 56	$ 73

Electric Utility Plant, Net

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

	June 30, 2018	December 31, 2017
Electric utility plant	$ 10,257	$ 9,914
Construction work-in-progress	290	391
Total cost	10,547	10,305
Less: accumulated depreciation and amortization	(3,707)	(3,564)
Electric utility plant, net	$ 6,840	$ 6,741

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $317 million and $296 million as of June 30, 2018 and December 31, 2017, respectively. Amortization expense related to intangible assets was $14 million and $27 million for the three and six months ended June 30, 2018, respectively, and $12 million and $23 million for the three and six months ended June 30, 2017, respectively. The Company’s intangible assets primarily consist of computer software development and hydro licensing costs.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

Regulatory Assets and Liabilities

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

	June 30, 2018		December 31, 2017	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 48	$ 135	$ 53	$ 151
Pension and other postretirement plans	—	209	—	218
Debt issuance costs	—	17	—	19
Trojan decommissioning activities	—	26	—	—
Other	8	54	9	50
Total regulatory assets	$ 56	$ 441	$ 62	$ 438
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 955	$ —	$ 933
Deferred income taxes	—	272	—	277
Trojan decommissioning activities	2	—	3	—
Asset retirement obligations	—	53	—	52
Tax Reform Deferral(1)	—	25	—	—
Other	20	43	28	26
Total regulatory liabilities	$ 22 (2)	$ 1,348	$ 31 (2)	$ 1,288

(1) Related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under TCJA.
(2) Included in Accrued expenses and other current liabilities in the condensed consolidated balance sheets.

Accrued Expenses and Other Current Liabilities

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

	June 30, 2018	December 31, 2017
Accrued employee compensation and benefits	$ 54	$ 60
Accrued taxes payable	25	31
Accrued interest payable	27	27
Accrued dividends payable	33	31
Regulatory liabilities—current	22	31
Other	64	61
Total accrued expenses and other current liabilities	$ 225	$ 241

Asset Retirement Obligations

Asset retirement obligations (AROs) consist of the following (in millions):

	June 30, 2018	December 31, 2017
Trojan decommissioning activities	$ 69	$ 45
Utility plant	110	109
Non-utility property	13	13
Asset retirement obligations	$ 192	$ 167

Trojan decommissioning activities represents the present value of future decommissioning costs for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that is licensed by the Nuclear Regulatory Commission (NRC). The ISFSI is to house 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 U.S. Department of Energy facility is complete, which is not expected prior to 2034. The NRC mandated an increase in staffing for the next 16 years that increased the Trojan ARO in the first quarter of 2018 by $23 million.

Credit Facilities

As of June 30, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, 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 credit facility. The facility contains a provision that requires annual fees based on PGE’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% of total capitalization. As of June 30, 2018, PGE was in compliance with this covenant with a 51.3% 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, limited to the unused amount of credit under the revolving credit facility.

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

Under the revolving credit facility, as of June 30, 2018, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, as of June 30, 2018, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total capacity of $220 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, letters of credit for a total of $64 million were outstanding as of June 30, 2018. Letters of credit issued are not reflected on the Company’s condensed consolidated balance sheets.

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Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount of up to $900 million through February 6, 2020.

Long-term Debt

During the six months ended June 30, 2018, PGE did not enter into any long-term debt transactions. Due to an anticipated repayment of $300 million of long-term debt in 2019, this amount was classified as current on the Company's condensed consolidated balance sheets as of June 30, 2018.

Defined Benefit Pension Plan Costs

Components of net periodic benefit cost under the defined benefit pension plan are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Service cost	$ 5	$ 4	$ 10	$ 8
Interest cost*	8	9	16	17
Expected return on plan assets*	(11)	(10)	(21)	(20)
Amortization of net actuarial loss*	4	3	8	6
Net periodic benefit cost	$ 6	$ 6	$ 13	$ 11

* The expense portion of non-service cost components are included in Miscellaneous income (expense), net within Other income on the Company's condensed consolidated statements of income and comprehensive income pursuant to ASU 2017-07. See Note 1, Basis of Presentation for additional information.

NOTE 4: 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 condensed consolidated balance sheets, for which it is practicable to estimate fair value as of June 30, 2018 and December 31, 2017. PGE then classifies these financial assets and liabilities based on a fair value hierarchy that is 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:

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; and

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 its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the

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economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the three and six months ended June 30, 2018 and 2017, 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):

	As of June 30, 2018				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Cash equivalents	$ 31	$ —	$ —	$ —	$ 31
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	3	7	—	—	10
Corporate credit	—	5	—	—	5
Money market funds measured at NAV [2]	—	—	—	27	27
Non-qualified benefit plan trust: [3]					
Money market funds	2	—	—	—	2
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Assets from price risk management activities: [1] [4]					
Electricity	—	1	2	—	3
Natural gas	—	1	—	—	1
	$ 44	$ 14	$ 2	$ 27	$ 87
Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 4	$ 116	$ —	$ 120
Natural gas	—	52	15	—	67
	$ —	$ 56	$ 131	$ —	$ 187

(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 $28 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Risk Management.

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	As of December 31, 2017				
	Level 1	Level 2	Level 3	Other [2]	Total
Assets:					
Cash equivalents	$ 30	$ —	$ —	$ —	$ 30
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	4	7	—	—	11
Corporate credit	—	6	—	—	6
Money market funds measured at NAV [2]	—	—	—	25	25
Non-qualified benefit plan trust: [3]					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Assets from price risk management activities: [1] [4]					
Electricity	—	3	—	—	3
Natural gas	—	3	—	—	3
	$ 43	$ 19	$ —	$ 25	$ 87
Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 5	$ 130	$ —	$ 135
Natural gas	—	66	9	—	75
	$ —	$ 71	$ 139	$ —	$ 210

(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 $28 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, 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 the fund's securities holdings do not exceed 90 days and investors have the ability to redeem the fund's shares daily at its respective net asset value. These 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 NASDAQ and the New York Stock Exchange.

Assets held in the Nuclear decommissioning trust and Non-qualified benefit plan (NQBP) trusts are recorded at fair value in PGE's condensed 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 yields and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Equity securities—Equity mutual fund and common stock 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. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange.

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.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's condensed consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net variable power costs (NVPC) for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, 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 June 30, 2018:							
Electricity physical forwards	$ 2	$ 116	Discounted cash flow	Electricity forward price (per MWh)	$ 11.29	$ 50.00	$ 33.35
Natural gas financial swaps	—	15	Discounted cash flow	Natural gas forward price (per Decatherm)	1.11	3.00	1.62
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	15.33	33.32	24.59
	$ 2	$ 131					
As of December 31, 2017:							
Electricity physical forwards	$ —	$ 130	Discounted cash flow	Electricity forward price (per MWh)	$ 7.79	$ 41.23	$ 30.95
Natural gas financial swaps	—	9	Discounted cash flow	Natural gas forward price (per Decatherm)	1.26	2.92	1.90
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	7.79	29.74	21.74
	$ —	$ 139					

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 PGE's position as either the buyer or seller under 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)

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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):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Balance as of the beginning of the period	134	144	$ 139	$ 119
Net realized and unrealized (gains)/losses*	(4)	9	(8)	35
Transfers out of Level 3 to Level 2	(1)	—	(2)	(1)
Balance as of the end of the period	$ 129	$ 153	$ 129	$ 153

* Both realized and unrealized (gains)/losses, of which the unrealized portion is fully offset by the effects of regulatory accounting until settlement of the underlying transactions, are recorded in Purchased power and fuel expense in the condensed consolidated statements of income and comprehensive income.

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. During the three and six months ended June 30, 2018 and 2017, there were no transfers into Level 3 from Level 2. 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 in and out of Level 3 at the end of the reporting period for all of its derivative instruments.

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 condensed consolidated balance sheets. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds is classified as a Level 2 fair value measurement. As of June 30, 2018, the carrying amount of PGE's long-term debt was $2,426 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,639 million. As of December 31, 2017, the carrying amount of PGE's long-term debt was $2,426 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,829 million.

NOTE 5: RISK MANAGEMENT

Price Risk Management

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Wholesale market transactions include purchases and sales of both power and fuel resulting from economic dispatch decisions for Company-owned generation resources. 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 may include forward, futures, swaps, and option contracts, which are recorded at fair value on the condensed consolidated balance sheets, for electricity, natural gas, and foreign currency, with changes in fair value recorded in the condensed consolidated statements of income. In accordance with the 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 engage in trading activities for non-retail purposes.

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

	June 30, 2018	December 31, 2017
Current assets:		
Commodity contracts:		
Electricity	$ 3	$ 3
Natural gas	1	3
Total current derivative assets*	4	6
Total derivative assets not designated as hedging instruments	$ 4	$ 6
Total derivative assets	$ 4	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 12	$ 13
Natural gas	39	46
Total current derivative liabilities	51	59
Noncurrent liabilities:		
Commodity contracts:		
Electricity	108	122
Natural gas	28	29
Total noncurrent derivative liabilities	136	151
Total derivative liabilities not designated as hedging instruments	$ 187	$ 210
Total derivative liabilities	$ 187	$ 210

* Included in Other current assets on the condensed consolidated balance sheets.

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

	June 30, 2018		December 31, 2017	
Commodity contracts:				
Electricity	5	MWh	7	MWh
Natural gas	112	Decatherms	114	Decatherms
Foreign currency	$ 22	Canadian	$ 21	Canadian

PGE has elected to report gross on the condensed consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. 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 June 30, 2018 and December 31, 2017, gross amounts included as Price risk management liabilities subject to master netting agreements were $122 million and $136 million, respectively, for which PGE posted collateral of $11 million, which consisted entirely of letters of credit. As of June 30, 2018, of the gross amounts recognized, $116 million was for electricity and $6 million was for natural gas compared to $130 million for electricity and $6 million for natural gas recognized as of December 31, 2017.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Commodity contracts:				
Electricity	$ (3)	$ 16	$ (2)	$ 49
Natural Gas	—	7	14	41
Foreign currency exchange	1	(1)	1	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the condensed consolidated statements of income and comprehensive income by the effects of regulatory accounting. Of the net amounts recognized in Net income for the three-month periods ended June 30, 2018 and 2017, net gains of $9 million and net losses of $4 million, respectively, have been offset. Net losses of $6 million and $65 million have been offset for the six-month periods ended June 30, 2018 and 2017, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of June 30, 2018 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2018	2019	2020	2021	2022	Thereafter	Total
Commodity contracts:							
Electricity	$ 4	$ 9	$ 8	$ 7	$ 7	$ 82	$ 117
Natural gas	25	25	11	5	—	—	66
Net unrealized loss	$ 29	$ 34	$ 19	$ 12	$ 7	$ 82	$ 183

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 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 June 30, 2018 was $183 million, for which PGE has posted $28 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2018, the cash requirement to either post as collateral or settle the instruments immediately would have been $182 million. As of June 30, 2018, 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 condensed consolidated balance sheet.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	June 30, 2018	December 31, 2017
Assets from price risk management activities:		
Counterparty A	39%	—%
Counterparty B	23	39
Counterparty C	18	7
Counterparty D	1	12
	81%	58%
Liabilities from price risk management activities:		
Counterparty E	62%	62%
	62%	62%

See Note 4, Fair Value of Financial Instruments, for additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities.

Interest Rate Risk

PGE has used a forward starting interest rate swap lock agreement to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. This derivative was designated as a cash flow hedge, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance.

The notional amount of the interest rate swap is $85 million with a mandatory cash settlement date in January 2019. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. Such amounts are also included as a component of cost of debt for ratemaking purposes.

PGE is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, PGE receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates. Until settlement, the interest rate swap is carried at fair value as a derivative asset or liability with the corresponding offset recorded as either a regulatory liability or regulatory asset, respectively. The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. As of June 30, 2018, the fair value of the interest rate swap was immaterial.

NOTE 6: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the period. 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 period using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; and ii) contingently issuable time-based and performance-based restricted stock units, along with associated dividend equivalent rights. Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria have been met.

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For the three and six months ended June 30, 2018, unvested performance-based restricted stock units and related dividend equivalent rights in the total amount of 231 thousand were excluded from the dilutive calculation because the performance goals had not been met, with 273 thousand excluded for the three and six months ended June 30, 2017.

Net income is the same for both the basic and diluted earnings per share computations. The denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Weighted-average common shares outstanding—basic and diluted	89,215	89,063	89,188	89,033

NOTE 7: EQUITY

The activity in equity during the six-month periods ended June 30, 2018 and 2017 is as follows (dollars in millions):

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balances as of December 31, 2017	89,114,265	$ 1,207	$ (8)	$ 1,217	$ 2,416
Issuances of shares pursuant to equity-based plans	123,941	—	—	—	—
Stock-based compensation	—	1	—	—	1
Dividends declared	—	—	—	(62)	(62)
Net income	—	—	—	110	110
Balances as of June 30, 2018	89,238,206	$ 1,208	$ (8)	$ 1,265	$ 2,465
Balances as of December 31, 2016	88,946,704	$ 1,201	$ (7)	$ 1,150	$ 2,344
Issuances of shares pursuant to equity-based plans	115,856	1	—	—	1
Stock-based compensation	—	1	—	—	1
Dividends declared	—	—	—	(59)	(59)
Net income	—	—	—	105	105
Balances as of June 30, 2017	89,062,560	$ 1,203	$ (7)	$ 1,196	$ 2,392

NOTE 8: 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. Contingencies are evaluated using the best information available at the time the condensed consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. 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.

Loss 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 an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then PGE: 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.

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 the subsequent reporting period.

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, will 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.

Carty

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the Contractor), affiliates of Abengoa S.A., for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the Sureties) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement. PGE, the Contractor, Abengoa S.A., and the Sureties are hereinafter collectively referred to as the Parties.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and completed construction.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of June 30, 2018, PGE has capitalized $640 million to Electric utility plant.

The excess costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, completing the remaining construction work, correcting deficiencies and defects in work performed by the Contractor, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, resolving claims and removing certain liens filed on the property for goods and services provided under contracts with the Contractor, and procuring additional materials.

The Company sought recovery of excess construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties denied liability in whole under the Performance Bond, and the Contractor filed claims against the Company alleging wrongful termination of contract and related damages.

Various actions relating to this matter were filed in the U.S. District Court for the District of Oregon, in the Ninth Circuit Court of Appeals, and in the International Chamber of Commerce’s Court of Arbitration.

As a result of the foregoing events, PGE has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest, and legal expenses. These incremental expenses are recognized in the Company’s current results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Such incremental expenses were $4 million and $7 million for the three and six months ended June 30, 2018, respectively, and $3 million and $7 million for the three and six months ended June 30, 2017, respectively.

The excess costs recorded to date exclude liens and claims filed for goods and services provided under contracts with the Contractor that remain in dispute of up to $5 million. The Company believes these claims by subcontractors are not owed by the Company and is contesting the liens and claims in the courts.

Subsequent to June 30, 2018, on July 16, 2018, the Parties reached a settlement to resolve all claims relating to Carty construction between the Company and each of the Contractor, Abengoa S.A., and the Sureties. Under the terms of the settlement, i) the Sureties will pay $130 million to PGE, and ii) the Contractor, Abengoa S.A., and the Sureties will release all claims against the Company arising out of the Carty construction, and in return, PGE will release all such claims against the Contractor, Abengoa S.A., and the Sureties.

The settlement will be treated as a subsequent event that will be recorded in PGE’s financial statements for the third quarter ending September 30, 2018. PGE is in the process of assessing the impact of the settlement to its financial position, results of operations, and cash flows. The Company anticipates that the proceeds will fully offset the incremental construction costs, thus eliminating ongoing excess depreciation and amortization, interest expense, and partially offsetting the Company’s other accumulated damages.

In July 2016, PGE requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the excess capital costs for Carty, starting from its in-service date to the date that such amounts are approved in a subsequent regulatory proceeding. The Company requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE’s actions against the Sureties, have been resolved. As a result of the settlement described above, the Company plans to withdraw the deferral application.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor that began in 1997 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 and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the original PRPs as it historically owned or operated property near the river.

In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. The EPA then listed additional PRPs, which now number over one hundred.

The Portland Harbor site remedial investigation had been 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 on January 6, 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which had an 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, for a combined discounted present value of $1.1 billion. 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. 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. In December 2017, the EPA announced that four PRPs have entered into an administrative order on consent to conduct this additional sampling, which was estimated to be completed in two years. PGE is not among the four PRPs performing this sampling.

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 results of the pre-remedial design sampling, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor.

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state trustees may seek to recover for such damages, which are referred to as Natural Resource Damages (NRD). As it relates to Portland Harbor, PGE continues to participate in the NRD assessment process. The EPA does not manage NRD assessment activities but provides 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 of Oregon, and certain tribal entities.

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. The NRD trustees are in the process of negotiating NRD liability with several PRPs, including PGE. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

Significant uncertainties remain 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, the amount of NRD, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, 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, although such costs could be material. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through claims under insurance policies and regulatory recovery in customer prices.

In 2016, the Company filed an application with the OPUC seeking the deferral of future environmental remediation costs as well as seeking authorization to establish a regulatory cost recovery mechanism for such environmental costs. In the first quarter of 2017, the OPUC approved the deferral request and a mechanism that will allow the Company to defer and recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and customer prices, as necessary. The mechanism establishes annual prudency reviews of environmental expenditures and is subject to an annual earnings test.

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate legal proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In August 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds of $33 million, including interest, which refunds were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in 2013 and by the OSC in 2014.

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement and in July 2015, heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. In April 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. A Court of Appeals decision remains pending.

PGE believes that the 2014 OSC decision and the Circuit Court decisions that followed have reduced the risk of any loss to the Company beyond the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Deschutes River Alliance Clean Water Act Claims

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company (Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon) that seeks injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claims PGE has violated certain conditions contained in PGE’s Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleges the violations are related to PGE’s operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam on the Deschutes River in central Oregon, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements, for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE’s operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the Deschutes River’s fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA’s members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that the FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE’s motion to dismiss. On April 7, 2017, the U.S. District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (CTWS) to appear in the case as a friend of the court. The CTWS shares ownership of the Project with PGE, but was not initially named as a defendant.

Following conferences and negotiations involving various parties, the District Court Judge (Judge), on January 17, 2018, established a briefing schedule for summary judgment motions and scheduled a bench trial to start December 3, 2018. In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the CTWS filed separate motions to dismiss. At a hearing on May 9, 2018, the Judge requested that PGE file an alternative motion to dismiss, which the Company and the CTWS filed on May 16, 2018. On June 11, 2018, the court denied the motions to dismiss filed in March 2018 and held that the CTWS was a necessary party to the lawsuit. DRA thereafter joined the CTWS as a defendant. At a hearing on July 17, 2018, the Judge heard and took under advisement the cross-motions for summary judgment and the motions to dismiss filed by PGE and the CTWS on May 16, 2018. The Judge also struck all future calendar dates, including the trial date.

The Company cannot predict the outcome of this matter, but believes that it has strong defenses to DRA’s claims and intends to defend against them. Because: i) this matter involves novel issues of law; and ii) the mechanism and costs for achieving the relief sought in DRA’s claims have not yet been determined, the Company cannot, at this time, determine the likelihood of whether the outcome of this matter will result in a material loss.

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 that may result in judgments against the Company. Although management currently believes that resolution of such 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 9: GUARANTEES

PGE enters into financial agreements and power and natural gas purchase and sale agreements 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. As of June 30, 2018, 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 condensed consolidated balance sheets with respect to these indemnities.

NOTE 10: INCOME TAXES

Income tax expense for interim periods is based on the estimated annual effective tax rate, which includes regulatory flow-through adjustments, tax credits, and other items, applied to the Company's year-to-date, pre-tax income. The significant differences between the U.S. Federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Federal statutory tax rate	21.0 %	35.0 %	21.0 %	35.0 %
Federal tax credits*	(17.0)	(12.4)	(17.5)	(15.0)
State and local taxes, net of federal tax benefit	6.5	5.2	6.5	5.1
Flow through depreciation and cost basis differences	(2.2)	(1.7)	(3.4)	0.1
Other	3.2	(2.3)	4.7	(1.3)
Effective tax rate	11.5 %	23.8 %	11.3 %	23.9 %

* Federal tax credits consists of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal 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. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ends at various dates through 2024.

On December 22, 2017, the TCJA was enacted and, among other provisions, reduced the federal corporate tax rate from 35% to 21%. The change in federal statutory tax rate is the primary driver of the change in effective tax rate from 2017 to 2018. As a result of the change in corporate tax rate, PGE is incurring lower income tax expense in 2018 than was estimated in setting customer prices in the Company's 2018 General Rate Case (2018 GRC). In a deferral filing with the OPUC on December 29, 2017, PGE has proposed to defer and refund the 2018 expected net benefits of the TCJA. If approved as requested, any refund to customers of the net benefits associated with the TCJA in 2018 would be subject to an earnings test and limited by the Company's currently authorized regulated return on equity. Under the proposed deferral filing, PGE has recorded a net refund to customers of $25 million as of June 30, 2018, which was recorded as a reduction to Revenues, net on the condensed consolidated statements of income and comprehensive income and an increase to Regulatory liabilities on the condensed consolidated balance sheets.

In accordance with tax normalization rules, the benefits of the 2017 deferred tax remeasurement of plant-related deferred taxes will be passed on to customers through future prices over the remaining useful life of the underlying assets for which the deferred income taxes relate. PGE has commenced amortization using the average rate assumption method to account for the refund to customers; however, as customer prices are not anticipated to be adjusted until 2019, such amortization has been deferred in Income tax expense and recorded as a Regulatory liability. As of June 30, 2018, PGE has deferred $4 million in tax normalization refunds.

Carryforwards

Federal tax credit carryforwards as of June 30, 2018 and December 31, 2017 were $55 million and $50 million, respectively. These credits consist of PTCs, which will expire at various dates through 2038. PGE has analyzed the provisions of the TCJA and its effects on the Company's deferred income tax assets, and PGE believes that it is more likely than not that its deferred income tax assets as of June 30, 2018 will be realized; accordingly, no valuation allowance has been recorded. As of June 30, 2018 and December 31, 2017, PGE had no unrecognized tax benefits.

Item 2. 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, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance, and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," 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 forward-looking statements 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 the expectations, beliefs, or projections contained in such forward-looking statements will be achieved or accomplished.

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and the OPUC 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 and capital investments, and current or prospective wholesale and retail competition;
- 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;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 8, Contingencies, in the Notes to the Condensed Consolidated Financial Statements;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;

- operational factors affecting PGE’s power generating facilities, including forced outages, 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;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company’s inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties 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 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, 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, and the repayments of maturing debt;
- 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, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company’s costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE’s service territory;
- the effectiveness of PGE’s risk management policies and procedures;
- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company’s generation, transmission, and distribution facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and a significant number of employees approaching retirement;
- new federal, state, and local laws that could have adverse effects on operating results, including the potential impact of the U.S. Tax Cuts and Jobs Act (TCJA);
- political and economic conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

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. This MD&A should be read in conjunction with the Company’s condensed consolidated financial statements contained in this report, as well as the consolidated financial statements and disclosures in its Annual Report on Form 10-K for the year ended December 31, 2017, 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, as well as the wholesale purchase and sale of electricity and natural gas in order to meet the needs of its retail customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory.

PGE is responding proactively to an evolving landscape of customer expectations, technology changes, and regulatory frameworks by focusing efforts on four strategic initiatives: i) deliver exceptional customer service; ii) invest in a reliable and clean energy future; iii) build a smarter, more resilient grid; and iv) pursue excellence in its work. The Company is participating in the development of a report from the OPUC to the Oregon legislature that was required under Senate Bill 978, which deals with the existing regulatory system, incentives and obligations currently employed by the OPUC. For further information, see *“SB 978”* in this Overview section of Item 2.

To deliver exceptional customer service, PGE must respond to the changing expectations of its customer base. The Company’s Integrated Resource Plan (IRP), new customer information system, and planned infrastructure investments are part of a strategy focused on providing power supply, distribution reliability, and customer service that meet those expectations.

PGE’s investments in a reliable and clean energy future are a key element of the IRP, which will require compliance with statutory renewable standards and consideration of state and local government initiatives to decarbonize the statewide economy.

Building a smarter, more resilient grid is essential to delivering the affordable, clean energy future that customers want. This requires embracing new technologies, modernizing the Company’s existing infrastructure, and implementation of a new customer information system to create a foundation to integrate emerging technologies. PGE’s capital requirements contemplate the impact of making these improvements to its transmission, distribution, and information technology infrastructure.

PGE’s 2016 IRP addressed the Company’s proposal to meet future customer demand and described PGE’s future energy supply strategy and anticipated resource needs over the next 20 years. The areas of focus for the plan included, among other topics, additional resources needed to meet Oregon’s Renewable Portfolio Standard (RPS) requirements and to replace energy from Boardman, the Company’s coal-fired generating plant located in Eastern Oregon that will cease coal-fired operations at the end of 2020. For further information regarding the 2016 IRP, the update to it, and the resulting Request for Proposal for the addition of RPS-compliant renewable resources (Renewable RFP), see *“Integrated Resource Plan”* in this Overview section of Item 2.

In February 2018, PGE filed a general rate case for a 2019 test year (2019 GRC). The Company expects the OPUC to authorize new customer prices effective January 1, 2019. For further information, see *“General Rate Case”* in this Overview section of Item 2.

As a market participant in the California Independent System Operator’s (CAISO) Energy Imbalance Market (western EIM), PGE has designated certain of its generating plants to receive automated dispatch signals from the CAISO that allows for load balancing with other EIM participants. The Company expects its western EIM participation will help integrate more renewable energy into the grid and provide access to the least-cost energy available in the region to meet changes in real-time energy demand and short-term variations in customer demand. The Company continues to work with the CAISO and regional partners on targeted market enhancements to the western EIM design, and also continues to participate in dialogue related to the development of a regional day-ahead market that could deliver additional benefits.

The discussion that follows in this MD&A provides additional information related to the Company's operating activities, legal, regulatory, and environmental matters, results of operations, and liquidity and financing activities.

Integrated Resource Plan—In August 2017, the OPUC acknowledged PGE's 2016 IRP and action plan items to, among other things:

- meet additional capacity needs;
- acquire cost-effective energy efficiency;
- acquire demand response and dispatchable standby generation; and
- submit one or more energy storage proposals in accordance with Oregon House Bill 2193.

Capacity—As part of the 2016 IRP, the Company put forth a variety of scenarios to meet future capacity needs, driven by the need to replace the output of Boardman, which will cease coal-fired generation by the end of 2020. As a result of the public review process, the Company pursued and has finalized bilateral power purchase agreements with capacity providers in the region, summarized as follows:

- 200 MW of annual capacity with five-year terms beginning January 1, 2021; and
- 100 MW of seasonal peak capacity during the summer and winter seasons with a term that begins July 1, 2019 and continues through February 29, 2024.

Renewables—In November 2017, PGE submitted to the OPUC an addendum to the 2016 IRP that included a request for the issuance of a Renewable RFP. In December 2017, the OPUC acknowledged the addendum and, as a result, in May 2018, PGE issued the Renewable RFP seeking a 100 MWa procurement target. The Company is in the process of evaluating the proposals received, which were due in June 2018, with the oversight of an independent evaluator and review by the OPUC.

PGE submitted a benchmark proposal into the Renewable RFP process that includes a wind resource that could have a nameplate capacity of up to 300 MW and would qualify for the federal production tax credit. The benchmark proposal will be considered along with other renewable resource proposals. A final shortlist of proposals is expected to be submitted to the OPUC in October 2018.

Energy Storage—Pursuant to OPUC acknowledgment of the 2016 IRP, and in accordance with Oregon House Bill 2193 (HB 2193), PGE filed an energy storage proposal in November 2017. The proposal called for 39 MW of storage to be developed over the next several years at various locations across the grid, at a cost of $50 to $100 million. Partial stipulations have been filed regarding most issues raised in this proposal and, as a result, the Company has revised its cost estimates and now expects capital spending on projects under the proposal would be approximately $45 million. The OPUC is to review the proposed projects and provide approval or modifications with a target decision date of August 15, 2018.

IRP Update—In March 2018, PGE filed an update to its 2016 IRP with the OPUC. The OPUC acknowledged the IRP Update at its April 24, 2018 meeting, and, as a result, PGE included the resource and financial parameters in its May 1, 2018 annual avoided cost update filing.

Since 2016, the Company has experienced significant growth in contract requests from Qualifying Facilities (QFs) under the Public Utilities Regulatory Policies Act. PGE continues to see a trend in which QF contracts are executed and subsequently packaged and sold to large, sophisticated multi-national developers in an attempt to take advantage of contract rates that are significantly higher than current market rates. PGE will attempt to work with the OPUC and stakeholders to restructure the QF implementation process to align with RPS targets to ensure customers receive affordable and reliable renewable energy, while continuing to comply with legal requirements.

As part of the IRP Update filing, PGE's capacity need has been updated to reflect the recently executed bilateral capacity contracts, changes to load forecast, and additional executed QF contracts. PGE expects that the anticipated procurement of resources through the Renewable RFP and energy storage associated with the HB 2193 will contribute to meeting the remaining forecasted need identified in the 2016 IRP.

General Rate Case—On February 15, 2018, the Company filed with the OPUC a GRC based on a 2019 test year (2019 GRC). After adjusting for the effects of the TCJA, the Company's filing requested an approximate 4.8% overall increase relative to currently approved prices and would have resulted in an $86 million increase in the annual revenue requirement. The filing sought recovery of costs related to better serving customers and building a smarter, more resilient system and included the expectation of higher net variable power costs in 2019.

Primary elements included:

- Installation of a new customer information system to provide better, more secure service;
- Replacement and upgrades to equipment to ensure system safety and reliability;
- Equip substations with technology to address potential outages and shorten those that do occur;
- Strengthen safeguards that protect against cyber attacks and other potential threats; and
- Add infrastructure to support rapid growth in the region.

The net increase in annual revenue requirement, as requested, was based upon:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.50%;
- A cost of capital of 7.31%; and
- A rate base of $4.86 billion.

PGE, interveners, and the OPUC Staff are currently in the settlement discussion phase of the public proceeding. The Company filed reply testimony on July 13, 2018. Regulatory review of the 2019 GRC will continue throughout 2018, with a final order targeted to be issued by the OPUC by mid-December 2018. New customer prices are expected to become effective January 1, 2019.

The 2019 GRC filing (OPUC Docket UE 335), as well as copies of direct and reply testimony and exhibits, are available on the OPUC website at www.oregon.gov/puc.

Tax Reform—On December 22, 2017, the TCJA was enacted and signed into law with substantially all of the provisions of the TCJA having an effective date of January 1, 2018. Among other provisions, the TCJA reduced the federal corporate tax rate from 35% to 21%. As a result of the change in corporate tax rate, PGE expects to incur lower income tax expense throughout 2018 than what was estimated in setting customer prices in the Company's 2018 GRC. PGE has proposed in a filing with the OPUC on December 29, 2017, to track and defer tax savings as a result of the TCJA and work with the OPUC to determine strategies to provide customers the appropriate benefit. This work is ongoing. If approved as requested, any refund to customers of the net benefits associated with the TCJA in 2018 would be subject to an earnings test and limited by the Company's currently authorized regulated return on equity. As of June 30, 2018, PGE has recorded a year-to-date net refund to customers of $25 million for net benefits expected in 2018. This deferral excludes the effects of applying an earnings test at the Company's authorized regulated return on equity, as well as other regulatory adjustments. The anticipated refund amount was recorded as a reduction to Revenues, net in the condensed consolidated statements of income and comprehensive income. The net impact to earnings of the reduction in revenue is largely offset by reduced income tax expense.

For additional information regarding income taxes, see Note 10, Income Taxes, in the Notes to Condensed Consolidated Financial Statements.

Capital Requirements and Financing—The Company expects 2018 capital expenditures to total $648 million, excluding AFDC. For additional information regarding estimated capital expenditures, see "*Capital Requirements*" in the Liquidity and Capital Resources section of this Item 2.

PGE plans to fund capital requirements with cash from operations during 2018, which is expected to range from $575 million to $625 million, the $130 million proceeds from the settlement of the Carty matter, and the issuance of debt securities of up to $75 million. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

Operating Activities—The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. PGE typically experiences its highest average MWh deliveries and retail energy sales during the winter heating season, although deliveries also increase during the summer months, generally resulting from air conditioning demand. Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

Customers and Demand—Retail energy deliveries for the six months ended June 30, 2018, decreased 3.9% compared with the six months ended June 30, 2017, as illustrated in the table below. This decrease was primarily driven by mild temperatures impacting usage in the residential and commercial classes.

During the first quarter of the calendar year, customer demand was influenced by mild temperatures during the heating season. During the first quarter of 2018, heating degree-days, an indication of the extent to which customers are likely to have used electricity for heating, were 19% below the first quarter of 2017.

During the second quarter of 2018, heating degree-days, were 31% below the second quarter of 2017. Also during the second quarter, cooling degree-days, an indication of the extent to which customers are likely to have used electricity for cooling, were 10% below prior year, indicating that temperature variations had a lesser effect on customer demand in the second quarter of 2018 when compared with 2017. See *"Revenues"* in the Results of Operations section of this Item 2 for further information on heating and cooling degree-days.

Residential energy deliveries decreased 0.9% in the second quarter of 2018 compared with the second quarter of 2017 reflecting decreased average usage per customer due to milder weather, partially offset by increased customer counts. Energy deliveries to commercial customers were comparable with the prior year quarter, while industrial deliveries were down 4.4% for the quarter largely due to a paper manufacturing closure in late 2017.

On a weather-adjusted basis, total energy deliveries increased 0.5% for the six months ended June 30, 2018. Growth in customer count and increased deliveries to high tech manufacturing customers continues to be partially offset by decreased average usage per customer driven by energy efficiency and conservation efforts. The financial effects of such efforts by residential and certain commercial customers are mitigated by the decoupling mechanism. See *"Legal, Regulatory and Environmental"* in this Overview section of Item 2 for further information on the decoupling mechanism.

The following table, which includes deliveries to the Company's Direct Access customers who purchase their energy from Electricity Service Suppliers, presents the average number of retail customers by customer type, and the corresponding energy deliveries, for the periods indicated:

	Six Months Ended June 30,				
	2018		2017		
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	% Increase (Decrease) in Energy Deliveries
Residential	770,247	3,745	759,765	4,009	(6.6)%
Commercial (PGE sales only)	107,834	3,251	106,593	3,342	(2.7)%
Direct Access	531	311	458	303	2.6 %
Total Commercial	108,365	3,562	107,051	3,645	(2.3)%
Industrial (PGE sales only)	206	1,397	198	1,435	(2.6)%
Direct Access	66	687	67	680	1.0 %
Total Industrial	272	2,084	265	2,115	(1.5)%
Total (PGE sales only)	878,287	8,393	866,556	8,786	(4.5)%
Total Direct Access	597	998	525	983	1.5 %
Total	878,884	9,391	867,081	9,769	(3.9)%

* In thousands of MWh.

The Company's Retail Customer Choice Program caps participation by Direct Access customers in the fixed three-year and minimum five-year opt-out programs, which account for the majority of energy supplied to Direct Access customers. This cap would have limited energy deliveries to these customers to an amount equal to approximately 14% of PGE's total retail energy deliveries for the first six months of 2018. Actual energy deliveries to Direct Access customers represented 10% of the Company's total retail energy deliveries for the full year 2017 and 11% for the first six months of 2018.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and power purchases in the wholesale market. In an effort to obtain reasonably-priced power for its retail customers, PGE makes economic dispatch decisions based on numerous factors including plant availability, customer demand, river flows, wind conditions, and current wholesale prices.

PGE's generating plants require varying levels of annual maintenance, during which the respective plants are unavailable to provide power. As a result, the amount of power generated to meet the Company's retail load requirement can vary from period to period. Plant availability, which is affected by both planned and unplanned outages, approximated 84% and 87% during the six months ended June 30, 2018 and 2017, respectively, for those plants PGE operates. Plant availability of Colstrip Units 3 and 4, of which the Company has a 20% ownership interest, approximated 94% and 79% during the six months ended June 30, 2018 and 2017, respectively.

During the six months ended June 30, 2018, the Company's generating plants provided 62% of its retail load requirement compared with 49% in the six months ended June 30, 2017. The increase in the proportion of power generated to meet the Company's retail load requirement was largely due to an increase in energy provided from the Company's natural gas-fired facilities due to lower fuel costs.

Energy expected to be received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects is projected annually in the Annual Power Cost Update Tariff (AUT). Any excess in such hydro generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the six months ended June 30, 2018, energy received from these hydro resources decreased by 10% compared to the six months ended June 30, 2017. Energy received from these hydro resources exceeded projected levels included in PGE's AUT by 5% and 14% for the six months ended June 30, 2018 and 2017, respectively, and provided 21% of the Company’s retail load requirement for the six months ended June 30, 2018 and 22% for the six months ended June 30, 2017. Energy from hydro resources is expected to approximate levels projected in the AUT for 2018.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT. Any excess in wind generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the six months ended June 30, 2018, energy received from these wind generating resources increased 35% compared to the six months ended June 30, 2017, resulting in the Company incurring less replacement costs, as well as generating more Production Tax Credits (PTCs) than what was estimated in customer prices. Energy received from these wind generating resources exceeded projections in PGE’s AUT by 6% for the six months ended June 30, 2018 and fell short of that projected in the AUT by 23% for the six months ended June 30, 2017, and provided 12% and 9% of the Company’s retail load requirement during the six months ended June 30, 2018 and 2017, respectively. Energy from wind resources is expected to exceed projected levels included in the AUT for 2018.

Pursuant to the Company’s power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year’s forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and 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 classified as Purchased power and fuel expense in the Company’s condensed consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income. Effective January 1, 2017, PGE’s AUT filings include projected PTCs for the respective calendar year with actual variances subject to the PCAM. To the extent actual annual NVPC, subject to certain adjustments, is above or below the deadband, which is a defined range from $30 million above to $15 million below baseline NVPC, the PCAM provides for 90% of the variance beyond the deadband to be collected from, or refunded to, customers, respectively, subject to a regulated earnings test.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in the Company’s condensed consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense.

For the six months ended June 30, 2018, actual NVPC was $27 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2018 is currently estimated to be below the $15 million baseline NVPC deadband range. Pursuant to the required regulated earnings test, PGE will not refund 90% of the excess variance to customers as the Company’s forecasted regulated return on equity for 2018 is less than its latest authorized ROE of 9.5% plus 1%. Accordingly, no estimated refund to customers is expected under the PCAM for 2018.

For the six months ended June 30, 2017, actual NVPC was $5 million below baseline NVPC. For the year ended December 31, 2017, actual NVPC was $15 million above baseline NVPC, which was within the established deadband range. Accordingly, no estimated collection from customers was recorded pursuant to the PCAM for 2017.

PGE has contractual access to natural gas storage in Mist, Oregon from which it can draw in the event that natural gas supplies are interrupted or if economic factors require its use. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PGE’s Port Westward Unit 1 and Beaver natural gas-fired generating plants and the Port Westward Unit 2 natural gas-fired flexible capacity generating plant. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the construction of a new reservoir, compressor station, and 13-miles of pipeline, which are collectively designed to provide no-notice storage services to these PGE generating plants. NW Natural estimates construction will be completed during the winter of 2018-2019, at a cost of approximately $132 million. Due to the level of PGE’s involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes, during the construction period. As a result, PGE has recorded $120 million to construction work-in-progress (CWIP) and a corresponding liability for the same amount to Other noncurrent liabilities in the condensed consolidated balance sheets as of June 30, 2018. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease.

Legal, Regulatory, and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which may have a material impact on the results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, an investigation of environmental matters regarding Portland Harbor.

Carty—Pursuant to the final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 GRC, the Company was authorized to include in customer prices the capital costs for Carty of up to $514 million, as well as Carty's operating costs, effective August 1, 2016, following the placement of the plant into service on July 29, 2016.

As the final construction cost of $640 million exceeded the amount authorized by the OPUC, PGE has been incurring higher interest and depreciation expense than allowed in the Company's revenue requirement. This higher cost of service is primarily due to depreciation and amortization on the incremental capital cost, interest expense, and legal expense, all of which totaled $7 million for the six months ended June 30, 2018 and is reflected in the Company's results of operations.

On July 16, 2018, the Company entered into a settlement to resolve all claims relating to Carty construction between the Company and each of the Contractor, Abengoa S.A., and the Sureties. Under the terms of the settlement, i) the Sureties will pay $130 million to PGE, and ii) the Contractor, Abengoa S.A., and the Sureties will release all claims against the Company arising out of the Carty construction, and in return, PGE will release all such claims against the Contractor, Abengoa S.A., and the Sureties. The Company anticipates that the proceeds will fully offset the incremental construction costs, thus eliminating ongoing excess depreciation and amortization, interest expense, and partially offsetting the Company's other accumulated damages. The settlement will be treated as a subsequent event that will be recorded in PGE's financial statements for the third quarter ending September 30, 2018.

For additional details regarding various legal and regulatory proceedings related to Carty and other matters, see Note 8, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

Clean Power Plan—In August 2015, the U.S. Environmental Protection Agency (EPA) released a final rule, which it called the "Clean Power Plan" (CPP). Under the final rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA. The rule established state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The rule was intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

The target amount was determined based on the EPA's view of the options for each state, including: i) making efficiency upgrades at fossil fuel-fired power plants; ii) shifting generation from coal-fired plants to natural gas-fired plants; and iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy). The final goal would need to be met by 2030 and interim goals for each state would need to be met from 2022 to 2029. Under the rule, states would have flexibility in designing programs to meet their emission reduction targets, including the three approaches noted above and any other measures the states choose to adopt (such as carbon tax and cap-and-trade) that would result in verified emission reductions.

PGE cannot predict how the states in which the Company's thermal generation facilities are located (Oregon and Montana) will implement the rule or how the rule may impact the Company's operations. PGE continues to monitor the developments around the implementation of the rule and efforts by state regulators to develop state plans. In

February 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the CPP pending the resolution of legal challenges to the rule.

In March 2017, the President of the United States issued an Executive Order that, among other items, specifically directed the EPA to take several actions relating to the CPP. The EPA was instructed to review the final CPP and the final new source performance standard rules for new and modified power plants under the Clean Air Act and suspend, revise, or rescind the rules, if appropriate. On October 16, 2017, the EPA published a proposed rule in which it outlined the rationale for repealing the CPP. The public comment period for the repeal rule closed April 26, 2018. Additionally, on December 28, 2017, the EPA published in the Federal Register an Advance Notice of Proposed Rulemaking (ANPR) seeking public comment on specific topics for the EPA to consider in developing any subsequent replacement rule. The public comment period on the ANPR closed February 26, 2018.

The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges and the regulatory process of the EPA, or whether Oregon will continue to develop an implementation plan in light of recent activities. The Company continues to monitor the developments around the potential new rule.

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill (SB) 1547, effective in March 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan. The legislation has impacted PGE in several ways, one of which is to prevent the Company from including the costs and benefits associated with coal-fired generation in Oregon retail prices after 2030 (subject to an exception that extends this date until 2035 for PGE’s output from the Colstrip facility). As a result, in October 2016, the Company filed a tariff request, which the OPUC approved, to incorporate in customer prices, on January 1, 2017, the approximate $6 million annual effect of accelerating recovery of PGE’s investment in the Colstrip facility from 2042 to 2030, as required under the legislation.

Future effects under the law include:

- an increase in RPS thresholds to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- a limitation on the life of renewable energy certificates (RECs) generated from facilities that become operational after 2022 to five years, but continued unlimited lifespan for all existing RECs and allowance for the generation of additional unlimited RECs for a period of five years for projects on line before December 31, 2022; and
- an allowance for energy storage costs related to renewable energy in its renewable adjustment clause mechanism (RAC) filings.

The Company evaluated the potential impacts and incorporated the effects of the legislation into its 2016 IRP.

SB 978—The State of Oregon legislature passed a bill in its 2017 session referred to as SB 978, which directs the OPUC to investigate and provide a report to the legislature by September 15, 2018 on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. PGE is actively working on this initiative, both internally and in conjunction with the OPUC, to provide guidance and support to develop the report.

Green Tariff —The Company recently submitted an application to the OPUC for a proposed green tariff program that would allow business customers to access bundled renewable energy. Through this proposed tariff, the Company seeks to align sustainability goals, cost and risk management, reliable integrated power, and a cleaner energy system. PGE proposes to avoid stranded costs and cost shifting by having subscribers continue under the Company’s existing cost of service tariff, with the green tariff added, and the procurement of energy through the use of power purchase agreements for competitive, renewable resources.

SB 1070—The State of Oregon legislators proposed SB 1070, referred to as the Clean Energy Jobs Bill, in an effort to reduce greenhouse gas emissions that contribute to climate change, through a statewide cap and trade program. The proposed legislation did not emerge from the 35-day legislative session that ended in March 2018. PGE continues to monitor developments around greenhouse gas emissions and any proposed legislation.

Other Regulatory Matters—The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for the first half of 2018 compared to the first half of 2017, or have affected retail customer prices, as authorized by the OPUC. In some cases, the Company has deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Power Costs—Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC in December 2017, the 2018 GRC included a final projected reduction in power costs for 2018, and a corresponding reduction in annual revenue requirement, of $40 million from 2017 levels, which is reflected in customer prices effective January 1, 2018.

Under the PCAM for 2017, NVPC was within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC will review the results of the PCAM for 2017 during the latter half of 2018 with a decision expected in the fourth quarter 2018.

Renewable Resource Costs—Pursuant to the RAC, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices expected to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date. No significant filings have been submitted under the RAC during 2018 or 2017.

Decoupling—The decoupling mechanism, which the OPUC has authorized through 2019, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency, customer-owned generation, and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

Accordingly, a refund of the $9 million recorded in 2015 that resulted from variances between actual weather-adjusted use per customer and that projected in the 2015 GRC, was refunded to customers over a one-year period, which began January 1, 2017. The Company recorded an estimated collection of $3 million during the year ended December 31, 2016, as a result of variances from amounts established in the 2016 GRC, with collection expected to occur over a one-year period, which began January 1, 2018. The Company recorded an estimated collection of $13 million during the year ended December 31, 2017, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2016 GRC. Any collection from customers for the 2017 year is expected to occur over a one-year period, which would begin January 1, 2019.

The Company recorded an estimated refund of $1 million during the six months ended June 30, 2018, which resulted from projections established in the 2018 GRC. Any collection from (or refund to) customers for the 2018 year is expected to occur over a one-year period, which would begin January 1, 2020. As part of the 2019 GRC, PGE has proposed certain modifications to the mechanism, which include establishing a balancing account approach to track the ongoing over- or under-collection status of the mechanism.

Storm Restoration Costs—Beginning in 2011, the OPUC authorized the Company to collect $2 million annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. The 2018 GRC, as approved by the OPUC, increased the annual collection amount to $3 million, beginning in 2018.

During 2015 and 2016, PGE fully utilized the existing reserve balance as a result of restoration costs associated with storm damage occurring during those years. As a result of a series of storm events in the first half of 2017, the Company exhausted the $2 million storm collection authorized for 2017. Consequently, PGE was exposed to the incremental costs related to such major storm events, which totaled $9 million, net of the $2 million amount collected in 2017.

As a result of the additional costs incurred, PGE filed an application with the OPUC requesting authorization to defer incremental storm restoration costs from the date of the application, in the first quarter of 2017, through the end of 2017, net of the $2 million being collected annually under the methodology at that time. The Company is unable to predict how the OPUC will ultimately rule on this application. The Company is unable to state with any certainty at this time whether these incremental costs are probable of recovery and, accordingly, no deferral has been recorded to-date. In the event it becomes probable that some or all of these costs are recoverable, the Company will record a deferral for such amounts at such time.

Portland Harbor Environmental Remediation Account Mechanism—In July 2016, PGE filed an application with the OPUC seeking the deferral of the future environmental remediation costs, as well as seeking authorization to establish a regulatory cost recovery mechanism for such environmental costs. In the first quarter of 2017, the OPUC approved the recovery mechanism, which allows the Company to defer and recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and customer prices, as necessary. The mechanism establishes annual prudency reviews of environmental expenditures and is subject to an annual earnings test.

Deferral of 2018 Net Benefits Associated with the TCJA—On December 29, 2017, PGE filed with the OPUC an application to defer the 2017 and 2018 financial impacts resulting from the new tax law. If the deferral application is approved as requested, any refund of the net benefits associated with tax reform will be subject to an earnings test and limited by the Company's currently authorized regulated return on equity. For more information regarding the effects of the new tax law on the Company, see the "Tax Reform" in the Overview section of this Item 2.

Critical Accounting Policies

Except for the updates to PGE's revenue recognition policy for the adoption of ASU 2014-09, *Revenue from Contracts with Customers* (Topic 606), the Company's critical accounting policies have remained consistent as outlined in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 16, 2018.

Revenue Recognition—PGE formally adopted ASU 2014-09, *Revenue from Contracts with Customers* effective January 1, 2018. The adoption of the new revenue standard did not have a material impact on PGE's revenue recognition policy as performance obligations are satisfied in a similar recognition pattern. Revenue is recognized under the right to invoice practical expedient for retail customers as they are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the meter read date through the last day of the month, an amount which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheets, is calculated based on each month's actual net retail system load, the number of days from the meter read date through the last day of the month, and current customer prices.

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.

PGE defines Gross margin as Total revenues less Purchased power and fuel. Gross margin is considered a non-GAAP measure as it excludes depreciation and amortization and other operation and maintenance expenses. The presentation of Gross margin is intended to supplement an understanding of PGE's operating performance in relation to changes in customer prices, fuel costs, impacts of weather, customer counts and usage patterns, and impact from regulatory mechanisms such as decoupling. The Company's definition of Gross margin may be different from similar terms used by other companies and may not be comparable to their measures.

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

	Three Months Ended June 30,						Six Months Ended June 30,					
	2018			2017			2018			2017		
Total revenues	$	449	100%	$	449	100%	$	942	100%	$	979	100%
Purchased power and fuel		104	23		118	26		234	25		259	26
Gross margin[1]		345	77		331	74		708	75		720	74
Other operating expenses:												
Generation, transmission and distribution		71	16		81	18		140	15		162	17
Administrative and other		70	15		64	15		139	14		131	13
Depreciation and amortization		93	21		86	19		185	20		170	17
Taxes other than income taxes		31	7		31	7		64	7		64	6
Total other operating expenses		265	59		262	58		528	56		527	54
Income from operations		80	18		69	15		180	19		193	20
Interest expense[2]		31	7		30	7		62	7		60	6
Other income:												
Allowance for equity funds used during construction		2	—		3	1		6	1		5	—
Miscellaneous income (expense), net		1	—		—	—		—	—		—	—
Other income, net		3	—		3	1		6	1		5	—
Income before income tax expense		52	11		42	9		124	13		138	14
Income tax expense		6	1		10	2		14	1		33	3
Net income	$	46	10%	$	32	7%	$	110	12%	$	105	11%

(1) Gross margin agrees to Total revenues less Purchased power and fuel as reported on PGE’s Condensed Consolidated Statements of Income and Comprehensive Income.
(2) Net of an allowance for borrowed funds used during construction of $1 million for the three months ended June 30, 2018 and 2017, and $3 million for the six months ended June 30, 2018 and 2017.

Net income was $46 million, or $0.51 per diluted share, for the three months ended June 30, 2018 compared with $32 million, or $0.36 per diluted share, for the three months ended June 30, 2017. The combination of changes in customer prices and lower average power costs driven by lower natural gas prices, partially offset by lower volumes of retail deliveries resulting from weather changes, produced improved gross margins in 2018. The increase in Net income also reflects the impact of the incremental storm costs recorded in 2017 and somewhat lower plant maintenance expenses in 2018. Administrative and other expenses increased marginally over the prior year, along with incremental costs associated with Carty, while an increase in PTCs helped offset the impact of the increase expenses during 2018.

Net income was $110 million, or $1.23 per diluted share, for the six months ended June 30, 2018, compared with $105 million, or $1.18 per diluted share, for the six months ended June 30, 2017. Temperature contrasts, as customers used less energy in the warmer 2018 heating season compared with the colder than average 2017 period, contributed to lower energy demand in the first half of 2018 than 2017 with Gross margin showing a slight decline. The Company recorded a small estimated refund under the Decoupling mechanism in the first half of 2018 compared with an $11 million estimated collection in the first half of 2017. The reduction in Generation, transmission and distribution expense reflects the significant storm related costs recorded in 2017 as well as lower plant maintenance expenses in 2018. Depreciation and amortization expense increased largely as a result of the expiration of customer credits, reflected in revenues, thus having no income impact. Although income tax expense reflects a significant reduction in 2018, driven by the TCJA, the reduction in expense is offset by a similar reduction in revenues, as the benefit is expected to be returned to customers in the future, thus having little net income impact.

Three Months Ended June 30, 2018 Compared with the Three Months Ended June 30, 2017

Revenues, energy deliveries (presented in MWh), and the average number of retail customers consist of the following for the periods presented:

	Three Months Ended June 30,			
	2018		2017	
Revenues (dollars in millions):				
Retail:				
Residential	$ 207	46 %	$ 203	45%
Commercial	162	36	158	35
Industrial	39	9	49	11
Direct access	13	3	9	2
Subtotal	421	94	419	93
Alternative revenue programs, net of amortization	—	—	—	—
Other accrued (deferred) revenues, net	(10)	(2)	1	—
Total retail revenues	411	92	420	93
Wholesale revenues	24	5	16	4
Other operating revenues	14	3	13	3
Total revenues	$ 449	100 %	$ 449	100%
Energy deliveries (MWh in thousands):				
Retail:				
Residential	1,612	29 %	1,626	31%
Commercial	1,654	30	1,655	32
Industrial	717	13	749	14
Subtotal	3,983	72	4,030	77
Direct access:				
Commercial	159	3	160	3
Industrial	342	6	359	7
Subtotal	501	9	519	10
Total retail energy deliveries	4,484	81	4,549	87
Wholesale energy deliveries	1,041	19	673	13
Total energy deliveries	5,525	100 %	5,222	100%
Average number of retail customers:				
Residential	771,608	88 %	761,443	88%
Commercial	108,939	12	107,620	12
Industrial	205	—	196	—
Direct access	596	—	572	—
Total	881,348	100 %	869,831	100%

Total revenues for the three months ended June 30, 2018 was comparable with the three months ended June 30, 2017, as Total retail revenues decreased $9 million while Wholesale and Other operating revenues were a total of $9 million higher.

The change in Total retail revenues resulted largely from the following:

- $10 million decrease to reflect the deferral of revenues for estimated refund to customers as a result of the TCJA, which is reflected in the Other accrued (deferred) revenues, net line in the table above. This reduction in revenues is offset with lower income tax expense, resulting in no overall net income impact. See *Tax Reform* in the Overview section of this Item 2 for further information;
- $6 million decrease resulting from 1.4% lower retail energy deliveries largely due to weather conditions. Energy deliveries to residential customers decreased 0.9% reflecting decreased average usage per customer due to changes in temperatures, which tracked closer to historical averages than was experienced during the first half of 2017. The decrease in average usage was partially offset by a 1.3% increase in the average number of customers. Energy deliveries to commercial customers remained flat while industrial deliveries declined 4.4% largely due to a paper manufacturing closure in late 2017; and
- $4 million decrease from the results of the Decoupling mechanism as a $1 million estimated collection was recorded in 2018, as opposed to an estimated $5 million collection in 2017; partially offset by
- $8 million increase that resulted from customer price changes; and
- $3 million increase as a result of the expiration of the credits to customers for the Trojan spent fuel refund at the end of 2017, the effect of which is offset in Depreciation and amortization expense.

During the three months ended June 30, the weather in the Company's service territory transitions retail customers from heating demand to cooling demand. For the three months ended June 30, 2018, both heating and cooling degree days were below 2017 levels, with total heating degree-days down 31% from the three months ended June 30, 2017, while cooling degree-days were down 10% from the prior year. For the three months ended June 30, 2018, the number of heating degree-days was 28% below the historical average while cooling degree days were 36% above the quarterly historical average, indicating a continued long-term trend to overall warmer temperatures compared to historical averages.

The following table indicates the number of heating and cooling degree-days for the three months ended June 30, 2018 and 2017, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days			**Cooling Degree-days**		
	2018	**2017**	**Avg.**	**2018**	**2017**	**Avg.**
April	338	421	373	9	—	2
May	89	196	204	34	41	19
June	44	69	79	73	88	64
Totals for the quarter	471	686	656	116	129	85
(Decrease)/increase from the 15-year average	(28)%	5%		36%	52%	

Wholesale revenues for the three months ended June 30, 2018 increased $8 million, or 50%, from the three months ended June 30, 2017, primarily as a result of a $9 million increase related to a 55% increase in wholesale sales volume.

Purchased power and fuel expense decreased $14 million, or 12%, for the three months ended June 30, 2018 compared with the three months ended June 30, 2017. This change consisted of a $21 million decrease due to a 17% decrease in the average variable power cost per MWh partially offset by a $7 million increase due to a 6% increase in total system load.

The decrease in the average variable power cost per MWh to $19.93 per MWh for the three months ended June 30, 2018 from $24.02 per MWh for the three months ended June 30, 2017, was primarily driven by a 7% decrease in average variable power cost per MWh on purchased power due to lower market prices and a 30% decrease in average variable power cost per MWh at PGE’s thermal generation facilities due to lower fuel costs and a larger portion of energy received from PGE lower cost generation sources.

Total system load increased 6% due primarily to a 55% increase in wholesale sales energy deliveries as retail loads were down slightly due to unfavorable weather conditions, as well as to take advantage of favorable market conditions.

The sources of energy for PGE’s total system load, as well as its retail load requirement, were as follows for the periods presented:

	Three Months Ended June 30,			
	2018		2017	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	828	16%	237	5%
Coal	421	8	256	5
Total thermal	1,249	24	493	10
Hydro	395	8	528	11
Wind	613	11	504	10
Total generation	2,257	43	1,525	31
Purchased power:				
Term	2,384	45	2,815	57
Hydro	500	10	503	10
Wind	94	2	85	2
Total purchased power	2,978	57	3,403	69
Total system load	5,235	100%	4,928	100%
Less: wholesale sales	(1,041)		(673)	
Retail load requirement	4,194		4,255	

Energy received from PGE-owned wind generating resources increased 22% in the three months ended June 30, 2018 compared with the same period of 2017 as a result of more favorable wind conditions. Energy received from these wind generating resources represented 15% and 12% of the Company’s retail load requirements for the three months ended June 30, 2018 and 2017, respectively. Due to less favorable hydroelectric conditions, energy received from hydro resources during the three months ended June 30, 2018, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 13% compared with the same period of 2017, and represented 21% and 24% of the Company’s retail load requirement for the three months ended June 30, 2018 and 2017, respectively.

The following table presents the forecast April-to-September 2018 runoff (issued July 18, 2018), along with actual 2017, at particular points of major rivers relevant to PGE’s hydro resources:

	Runoff as a Percent of Normal*	
Location	**2018 Forecast**	**2017 Actual**
Columbia River at The Dalles, Oregon	116%	124%
Mid-Columbia River at Grand Coulee, Washington	117	115
Clackamas River at Estacada, Oregon	87	127
Deschutes River at Moody, Oregon	89	111

* Volumetric water supply forecasts and historical 30-year averages (as measured over the period from 1981 through 2010) for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Actual NVPC for the three months ended June 30, 2018 decreased $23 million when compared with the three months ended June 30, 2017. The decrease was driven by a 17% decrease in the average variable power cost per MWh, partially offset by a 6% increase in total system load. The increase in wholesale revenues was driven primarily by a 55% increase in wholesale sales volume offset slightly by a 1% decrease in the average wholesale sales price. For the three months ended June 30, 2018, actual NVPC was $16 million below the baseline. For the three months ended June 30, 2017, actual NVPC was $3 million below baseline NVPC. For additional information, see "*Purchase power and fuel*" section of this Item 2.

Generation, transmission and distribution expense decreased $10 million, or 12%, in the three months ended June 30, 2018 compared with the three months ended June 30, 2017, driven by $5 million lower storm costs and $5 million lower plant maintenance and overhaul costs.

Administrative and other expense increased $6 million, or 9%, in the three months ended June 30, 2018 compared with the three months ended June 30, 2017. The increase was primarily due to a $2 million increase in employee incentives and $2 million higher legal fees.

Depreciation and amortization expense increased $7 million in the three months ended June 30, 2018 compared with the three months ended June 30, 2017. The increase was driven by a $4 million decrease in the amortization credit related to the Trojan spent fuel refund to customers, which was also reflected in revenues, and higher depreciation and amortization expense of $3 million resulting from increased capital additions.

Interest expense, net increased $1 million, or 3%, in the three months ended June 30, 2018 compared with the three months ended June 30, 2017, primarily due to a 3% increase in the average balance of outstanding debt.

Income tax expense decreased $4 million in the three months ended June 30, 2018 compared with the three months ended June 30, 2017, reflecting effective tax rates of 11.5% and 23.8%, respectively. The decrease in income tax expense was driven by a lower federal corporate tax rate pursuant to the TCJA and higher PTC's, offset by higher pre-tax income prior to application of the effect of the tax deferral.

Six Months Ended June 30, 2018 Compared with the Six Months Ended June 30, 2017

Revenues, energy deliveries (presented in MWh), and the average number of retail customers consist of the following for the periods presented:

	Six Months Ended June 30,			
	2018		2017	
Revenues (dollars in millions):				
Retail:				
Residential	$ 475	51 %	$ 491	50%
Commercial	313	33	315	32
Industrial	83	9	93	10
Direct Access	23	2	18	2
Subtotal	894	95	917	94
Alternative revenue programs, net of amortization	(2)	—	—	—
Other accrued (deferred) revenues, net	(27)	(3)	9	1
Total retail revenues	865	92	926	95
Wholesale revenues	52	5	29	3
Other operating revenues	25	3	24	2
Total revenues	$ 942	100 %	$ 979	100%
Energy deliveries (MWh in thousands):				
Retail:				
Residential	3,745	33 %	4,009	37%
Commercial	3,251	29	3,342	31
Industrial	1,397	12	1,435	13
Subtotal	8,393	74	8,786	81
Direct access:				
Commercial	311	3	303	3
Industrial	687	6	680	6
Subtotal	998	9	983	9
Total retail energy deliveries	9,391	83	9,769	90
Wholesale energy deliveries	1,915	17	1,112	10
Total energy deliveries	11,306	100 %	10,881	100%
Average number of retail customers:				
Residential	770,247	88 %	759,765	88%
Commercial	107,834	12	106,593	12
Industrial	206	—	198	—
Direct access	597	—	525	—
Total	878,884	100 %	867,081	100%

Total revenues for the six months ended June 30, 2018 decreased $37 million, or 4%, compared with the six months ended June 30, 2017, consisting primarily of a $61 million decrease in Total retail revenues, partially offset by a $23 million increase in Wholesale revenues.

The change in Retail revenues consisted primarily of the following factors:

- $36 million reduction resulted from the decrease in retail energy deliveries due largely to the effects of weather on electricity demand, which is reflected predominantly in the Residential revenue line in the table above. Considerably warmer temperatures in the first quarter of 2018 than experienced in 2017, which was colder than average, along with more moderate temperatures in the second quarter of 2018 than 2017, combined to drive deliveries lower;
- $25 million decrease to reflect the deferral of revenues for estimated refund to customers as a result of the TCJA, which is reflected in the Other accrued (deferred) revenues, net line in the table above. This reduction in revenues is offset with lower income tax expense, resulting in no overall net income impact; and
- $12 million decrease from the results of the Decoupling mechanism as an immaterial refund was recorded in 2018, as opposed to an estimated $11 million collection in 2017; partially offset by
- $8 million increase as a result of the expiration of the credits to customers for the Trojan spent fuel refund, the effect of which is offset in Depreciation and amortization expense; and
- $7 million increase in revenues as a result of price changes.

Total heating degree-days for the six months ended June 30, 2018 were 22% below those for the six months ended June 30, 2017 and 9% below average, while cooling degree-days, which usually begin during the second calendar quarters, were 10% below the prior year levels although 36% above average.

The following table indicates the number of heating and cooling degree-days for the six months ended June 30, 2018 and 2017, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days			Cooling Degree-days		
	2018	**2017**	**Avg.**	**2018**	**2017**	**Avg.**
First quarter	1,766	2,171	1,813	—	—	—
Second quarter	471	686	656	116	129	85
Year-to-date	2,237	2,857	2,469	116	129	85
(Decrease)/increase from the 15-year average	(9)%	16%		36%	52%	

Wholesale revenues for the six months ended June 30, 2018 increased $23 million, or 79%, from the six months ended June 30, 2017, with the increase comprised of $21 million related to a 72% increase in wholesale sales volumes and $3 million related to a 5% increase in average wholesale sales prices. Due to lower than expected retail customer demand and depressed natural gas prices in the first half of 2018, the Company economically generated and sold more power into the Wholesale market than in the comparable period of 2017.

Purchased power and fuel expense decreased $25 million, or 10%, for the six months ended June 30, 2018 compared with the six months ended June 30, 2017. This change consisted of $30 million related to a decrease in the average variable power cost per MWh, and a $6 million increase related to total system load.

The $30 million decrease in the average variable power cost to $21.51 per MWh in the six months ended June 30, 2018 from $24.65 per MWh in the six months ended June 30, 2017, was driven primarily by a larger portion of total system load provided by the Company's natural gas-fired generating facilities, which experienced a 42% reduction in the average variable power cost per MWh due to lower natural gas costs, and a 35% increase in energy delivered from the Company's wind generating resources.

The $6 million increase related to total system load was driven primarily by a 72% increase in wholesale deliveries, partially offset by lower retail energy deliveries.

The sources of energy for PGE’s total system load, as well as its retail load requirement, were as follows for the periods presented:

	Six Months Ended June 30,			
	2018		2017	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	2,691	24%	1,540	15%
Coal	966	9	1,167	11
Total thermal	3,657	33	2,707	26
Hydro	867	8	1,076	10
Wind	1,088	10	803	8
Total generation	5,612	51	4,586	44
Purchased power:				
Term	4,131	38	4,797	46
Hydro	1,006	9	1,000	9
Wind	152	2	124	1
Total purchased power	5,289	49	5,921	56
Total system load	10,901	100%	10,507	100%
Less: wholesale sales	(1,915)		(1,112)	
Retail load requirement	8,986		9,395	

Energy received from PGE-owned wind generating resources increased 35% in the six months ended June 30, 2018 compared with the same period of 2017 as a result of more favorable wind conditions. Energy received from these wind generating resources represented 12% and 9% of the Company’s retail load requirements for the six months ended June 30, 2018 and 2017, respectively. Due to less favorable hydroelectric conditions, energy received from hydro resources during the six months ended June 30, 2018, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 10% compared with the same period of 2017, and represented 21% and 22% of the Company’s retail load requirement for the six months ended June 30, 2018 and 2017, respectively.

Actual NVPC for the six months ended June 30, 2018 decreased $48 million when compared with the six months ended June 30, 2017. The decrease in purchased power and fuel was driven by a 13% decrease in the average variable power cost per MWh, partially offset by a 4% increase in total system load. The overall decrease in actual NVPC was also driven by a 79% increase in wholesale revenues. The change in wholesale revenues was due mostly to a 5% increase in wholesale sales price and a 72% increase in sales volume. For the six months ended June 30, 2018 and 2017, actual NVPC was $27 million and $5 million below baseline NVPC, respectively.

Generation, transmission and distribution expense decreased $22 million, or 14%, in the six months ended June 30, 2018 compared with the six months ended June 30, 2017 primarily due to $11 million lower overall storm and service restoration costs, and $11 million lower plant maintenance and overhaul expense.

Administrative and other expense increased $8 million, or 6%, in the six months ended June 30, 2018 compared with the six months ended June 30, 2017. The increase was primarily due to higher employee benefits, higher legal costs and other expenses.

Depreciation and amortization expense increased $15 million in the six months ended June 30, 2018 compared with the six months ended June 30, 2017. The increase was primarily driven by a $9 million decrease in the amortization credit related to the Trojan spent fuel refund to customers, which was also reflected in revenues, and $6 million increased plant depreciation and software amortization.

Interest expense, net increased $2 million, or 3%, in the six months ended June 30, 2018 compared with the six months ended June 30, 2017, primarily due to a 3% increase in the average balance of outstanding debt.

Other income, net was $6 million in the six months ended June 30, 2018 compared with $5 million in the six months ended June 30, 2017due primarily to an increase in the allowance for equity funds used during construction.

Income tax expense decreased $19 million in the six months ended June 30, 2018 compared with the six months ended June 30, 2017, with effective tax rates of 11.3% and 23.9%, respectively. The decrease in income tax expense was driven by a lower federal corporate tax rate pursuant to the TCJA, offset by higher pre-tax income prior to application of the effect of the tax deferral.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE's estimated capital expenditures and contractual maturities of long-term debt for 2018 through 2022 (in millions, excluding AFDC):

	2018	2019	2020	2021	2022
Ongoing capital expenditures (1)	$ 620	$ 452	$ 457	$ 448	$ 450
Customer information system (2)	28	—	—	—	—
Total capital expenditures	$ 648 (3)	$ 452	$ 457	$ 448	$ 450
Long-term debt maturities	$ —	$ 300	$ —	$ 160	$ —

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connections.
(2) As of December 31, 2017, total capital expenditures for the Customer information system were $114 million, excluding AFDC.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

For a discussion concerning PGE's ability to fund its future capital requirements, see *"Debt and Equity Financings"* in this Item 2.

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 distribution, transmission, and generation facilities to support both new and existing customers, 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 following summarizes PGE's cash flows for the periods presented (in millions):

	Six Months Ended June 30,	
	2018	2017
Cash and cash equivalents, beginning of period	$ 39	$ 6
Net cash provided by (used in):		
Operating activities	338	333
Investing activities	(265)	(245)
Financing activities	(64)	(61)
Increase in cash and cash equivalents	9	27
Cash and cash equivalents, end of period	$ 48	$ 33

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, with adjustments for certain non-cash items, such as depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. Net cash flows from operating activities for the six months ended June 30, 2018 increased $5 million when compared with the six months ended June 30, 2017. Included in the change were a number of somewhat offsetting components as follows:

- $29 million decrease from Accounts receivable, net and unbilled revenues;
- $15 million increase in Depreciation and amortization primarily due to Trojan spent fuel settlement at the end of 2017;
- $9 million increase from Accounts payable and accrued liabilities;
- $11 million net increase in Deferred income taxes and Deferral of net benefits due to Tax Reform
- $7 million decrease due to changes in inventory levels; and
- $5 million net increase from the combination of changes in Net income adjusted for non-cash income and expenses including: the Decoupling mechanism deferrals, net of amortization and Other non-cash income and expenses.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2018 will range from $365 million to $385 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $575 million to $625 million.

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 facilities and transmission and distribution systems. Net cash used in investing activities for the six months ended June 30, 2018 increased $20 million when compared with the six months ended June 30, 2017, largely due to the increased level of cash outflow for the customer information system implementation and other ongoing capital expenditures.

The Company plans to make capital expenditures of $648 million, excluding AFDC, in 2018, which it expects to fund with cash to be generated from operations during 2018, as discussed above, as well as with proceeds received from the settlement of the Carty matter and the issuances of debt securities. For additional information, see *"Debt and Equity Financings"* in this Liquidity and Capital Resources section of Item 2.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During the six months ended June 30, 2018, a net use of cash resulted from financing activities primarily for the payment of dividends of $61 million. During the six months ended June 30, 2017, net cash provided by financing activities consisted primarily of the payment of dividends of $57 million.

Dividends on Common Stock

While PGE expects to pay regular quarterly dividends on its common stock, the declaration of any dividends remains at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deems relevant, which may include, among other things, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Common stock dividends declared during 2018 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 14, 2018	March 26, 2018	April 16, 2018	$0.3400
April 25, 2018	June 25, 2018	July 16, 2018	0.3625
July 25, 2018	September 25, 2018	October 15, 2018	0.3625

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors. Management believes that the availability of its revolving credit facility, the expected ability to issue 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. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

For 2018, PGE expects to fund estimated capital requirements with cash from operations, which is expected to range from $575 million to $625 million, proceeds from the Carty settlement of $130 million, issuances of debt securities of up to $75 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt and commercial paper will be dependent upon the timing and amount of capital expenditures.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2020.

As of June 30, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. 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, two, 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 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.

As of June 30, 2018, PGE had no borrowings outstanding, and no commercial paper or letters of credit issued under the revolving credit facility. As a result, the aggregate, unused available credit capacity was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $64 million were outstanding as of June 30, 2018.

Long-term Debt. As of June 30, 2018, total long-term debt outstanding, net of $10 million of unamortized debt expense, was $2,426 million, with $300 million scheduled maturities classified as current. During the six months ended June 30, 2018, PGE did not enter into any long-term debt transactions.

Capital Structure. PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including any current debt maturities) of approximately 50%, over time. Achievement of this objective helps the Company maintain investment grade credit ratings and facilitates access to long-term capital at favorable interest rates. The Company's common equity ratio was 49.9% and 49.4% as of June 30, 2018 and December 31, 2017, respectively.

Credit Ratings and Debt Covenants

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

	Moody's	**S&P**
First Mortgage Bonds	A1	A
Senior unsecured debt	A3	BBB+
Commercial paper	P-2	A-2
Outlook	Stable	Positive

Should Moody's or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could 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, are based on the contract terms and commodity prices, and can vary from period to period. Cash deposits that PGE provides as collateral are classified as Margin deposits, which is included in Other current assets on the Company's condensed consolidated balance sheets, while any letters of credit issued are not reflected on the condensed consolidated balance sheets.

As of June 30, 2018, PGE had $35 million of collateral posted with these counterparties, consisting of $7 million in cash and $28 million in letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of June 30, 2018, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was $66 million, and decreases to $22 million by December 31, 2018 and to $8 million by December 31, 2019. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was $152 million at June 30, 2018, and decreases to $99 million by December 31, 2018 and to $67 million by December 31, 2019.

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 facility would increase.

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust (Indenture) securing the bonds. PGE estimates that on June 30, 2018, under the most restrictive issuance test in the Indenture, the Company could have issued up to $1.1 billion 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 under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facility contains 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 June 30, 2018, the Company's debt-to-total capital ratio, as calculated under the credit agreement, was 51.3%.

Off-Balance Sheet Arrangements

PGE has no off-balance sheet arrangements, other than outstanding letters of credit from time to time, that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contractual Obligations

PGE's contractual obligations for 2018 and beyond are set forth in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 16, 2018. For such obligations, there have been no material changes outside the ordinary course of business as of June 30, 2018, except for the following:

- Due to the incorporation of asset returns for 2017 into the forecasted obligation requirements, PGE expects contributions to the pension plan of $12 million in 2018, none in 2019, $35 million in 2020, $22 million in 2021, and $27 million in 2022; and
- PGE currently leases its corporate headquarters, however, in May 2018, PGE committed to purchase the corporate headquarters building for $45 million. Subject to OPUC approval, the purchase is expected to close in November 2018 and the building will be recorded as a non-utility asset.

Item 3. 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. There have been no material changes to market risks affecting the Company from those set forth in Part II, Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 16, 2018.

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

PGE’s management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company’s disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE’s Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2018, these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

In May 2018, PGE implemented a new customer information system to store customer data and to process metering, billing, and payment transactions. This system implementation improves the efficiency of PGE’s retail billing processes and resulted in a material change in PGE’s internal control over financial reporting. Other than PGE’s new customer information system, there were no changes in PGE’s internal control over financial reporting that occurred during the period covered by this quarterly report that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

See Note 8, Contingencies in the Notes to Condensed Consolidated Financial Statements in Item 1.—“Financial Statements,” for information regarding legal proceedings.

Item 1A. Risk Factors.

There have been no material changes to PGE’s risk factors set forth in Part I, Item 1A of the Company’s Annual Report on Form 10-K for the year ended December 31, 2017, filed with the SEC on February 16, 2018.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed May 9, 2014).
3.2	Tenth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K filed May 9, 2014).
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
32	Certifications of Chief Executive Officer and Chief Financial Officer.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Certain instruments defining the rights of holders of other long-term debt of the Company 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. The Company hereby agrees to furnish a copy of any such instrument to the SEC upon request.

SIGNATURE

Pursuant to the requirements 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.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date:	July 26, 2018	By:	/s/ James F. Lobdell
			James F. Lobdell
			Senior Vice President of Finance, *Chief Financial Officer and Treasurer*
			(duly authorized officer and principal financial officer)

Exhibit 31.1

CERTIFICATION

I, Maria M. Pope, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	July 26, 2018	By:	/s/ Maria M. Pope
			Maria M. Pope
			President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	July 26, 2018	By:	/s/ James F. Lobdell
			James F. Lobdell
			Senior Vice President of Finance, *Chief Financial Officer and Treasurer*

Exhibit 32

CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

We, Maria M. Pope, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018, as filed with the Securities and Exchange Commission on July 27, 2018 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Maria M. Pope	/s/ James F. Lobdell
Maria M. Pope	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: July 26, 2018	Date: July 26, 2018