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 March 31, 2019

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

[x] Yes x [ ] 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 [ ]	Smaller reporting company [ ]
	Emerging growth company [ ]

Table of Contents

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 April 17, 2019 is 89,356,572 shares.

Table of Contents

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2019

TABLE OF CONTENTS

Table of Contents

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
NASDAQ	National Association of Securities Dealers Automated Quotations
NVPC	Net Variable Power Costs
NYSE	New York Stock Exchange
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 of 2017
Trojan	Trojan nuclear power plant

Table of Contents

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 March 31,	
	2019	2018
Revenues:		
Revenues, net	$570	$495
Alternative revenue programs, net of amortization	3	(2)
Total revenues	573	493
Operating expenses:		
Purchased power and fuel	179	130
Generation, transmission and distribution	77	69
Administrative and other	71	69
Depreciation and amortization	101	92
Taxes other than income taxes	34	33
Total operating expenses	462	393
Income from operations	111	100
Interest expense, net	32	31
Other income:		
Allowance for equity funds used during construction	3	4
Miscellaneous income (expense), net	2	(1)
Other income, net	5	3
Income before income tax expense	84	72
Income tax expense	11	8
Net income	73	64
Other comprehensive income	1	—
Comprehensive income	$74	$64
Weighted-average common shares outstanding—basic and diluted (in thousands)	89,309	89,160
Earnings per share—basic and diluted	$0.82	$0.72

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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

	March 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89	$ 119
Accounts receivable, net	226	193
Unbilled revenues	71	96
Inventories	81	84
Regulatory assets—current	21	61
Other current assets	108	90
Total current assets	596	643
Electric utility plant, net	6,747	6,887
Regulatory assets—noncurrent	380	401
Nuclear decommissioning trust	46	42
Non-qualified benefit plan trust	37	36
Other noncurrent assets	142	101
Total assets	$ 7,948	$ 8,110

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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

	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 136	$ 168
Liabilities from price risk management activities—current	32	55
Current portion of long-term debt	300	300
Accrued expenses and other current liabilities	263	268
Total current liabilities	731	791
Long-term debt, net of current portion	2,178	2,178
Regulatory liabilities—noncurrent	1,356	1,355
Deferred income taxes	380	369
Unfunded status of pension and postretirement plans	309	307
Liabilities from price risk management activities—noncurrent	78	101
Asset retirement obligations	198	197
Non-qualified benefit plan liabilities	103	103
Other noncurrent liabilities	67	203
Total liabilities	5,400	5,604
Commitments and contingencies (see notes)		
Shareholders' Equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of March 31, 2019 and December 31, 2018	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,356,311 and 89,267,959 shares issued and outstanding as of March 31, 2019 and December 31, 2018, respectively	1,212	1,212
Accumulated other comprehensive loss	(8)	(7)
Retained earnings	1,344	1,301
Total shareholders' equity	2,548	2,506
Total liabilities and shareholders' equity	$ 7,948	$ 8,110

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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

	Three Months Ended March 31, 2019		2018	
Cash flows from operating activities:				
Net income	$ 73		$ 64	
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization	101		92	
Deferred income taxes	9		6	
Pension and other postretirement benefits	6		6	
Allowance for equity funds used during construction	(3	)	(4	)
Decoupling mechanism deferrals, net of amortization	(4	)	3	
(Amortization) Deferral of net benefits due to Tax Reform	(5	)	15	
Other non-cash income and expenses, net	10		4	
Changes in working capital:				
(Increase) decrease in accounts receivable and unbilled revenues	(1	)	45	
Decrease (increase) in inventories	3		(2	)
Decrease (increase) in margin deposits, net	1		(6	)
(Decrease) in accounts payable and accrued liabilities	(13	)	(17	)
Other working capital items, net	(12	)	(5	)
Other, net	(9	)	(7	)
Net cash provided by operating activities	156		194	
Cash flows from investing activities:				

Capital expenditures	(150	)	(131	)
Sales of Nuclear decommissioning trust securities	4		3	
Purchases of Nuclear decommissioning trust securities	(2	)	(3	)
Other, net	(3	)	1	
Net cash used in investing activities	(151	)	(130	)
Cash flows from financing activities:				
Dividends paid	(32	)	(30	)
Other	(3	)	(3	)
Net cash used in financing activities	(35	)	(33	)
(Decrease) increase in cash and cash equivalents	(30	)	31	
Cash and cash equivalents, beginning of period	119		39	
Cash and cash equivalents, end of period	$ 89		$ 70	
Supplemental cash flow information is as follows:				
Cash paid for interest, net of amounts capitalized	$ 13		$ 13	

See accompanying notes to condensed consolidated financial statements.

Table of Contents

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 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 March 31, 2019, PGE served 887 thousand retail customers with a service area population of 1.9 million, comprising 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 three months ended March 31, 2019 and 2018 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, 2018 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2018, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 15, 2019, 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 months ended March 31, 2019 and 2018.

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.

Table of Contents

Recent Accounting Pronouncements

In August 2018, the FASB issued ASU 2018-13 Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. ASU 2018-13 amends Topic 820 to add, remove, and clarify disclosure requirements related to fair value measurement disclosures. For calendar year-end entities, the update will be effective for annual periods beginning January 1, 2020, and interim periods within those fiscal years. Early adoption of the amendments is permitted, including adoption in any interim period. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the condensed consolidated financial statements and is still evaluating if it will early adopt.

In August 2018, the FASB issued ASU 2018-14 Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans. ASU 2018-14 amends Topic 715 to add, remove, and clarify disclosure requirements related to defined benefit pension and other postretirement plans. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2021. Early adoption is permitted. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the condensed consolidated financial statements and is still evaluating whether it will early adopt.

In August 2018, the FASB issued ASU 2018-15 Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2020. Early adoption is permitted, including adoption in an interim period. The amendments in this update may be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PGE is in the process of evaluating potential impacts of these amendments, and whether it will early adopt.

Recently Adopted Accounting Pronouncements

On January 1, 2019, PGE adopted ASU 2016-02, Leases (Topic 842), which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, Leases. The Company elected the practical expedient provided under ASU 2018-11, Leases (Topic 842) Targeted Improvements, which amended ASU 2016-02 to provide entities an optional transition practical expedient 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. As a result, no adjustments were made to the balance sheet prior to January 1, 2019 and amounts are reported in accordance with historical accounting under Topic 840, while the balance sheet as of March 31, 2019 is presented under Topic 842. The Company also elected the practical expedient provided under ASU 2018-01, Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842, which amended 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. Effective January 1, 2019, PGE will evaluate new or modified land easements under Topic 842.

PGE's transition to the new lease standard did not result in a material adjustment to beginning 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. Upon transition, PGE elected to reassess all arrangements that may contain a lease and their resulting lease classification which resulted in the following balance sheet adjustments as of January 1, 2019: i) the recognition of right-of-use assets and liabilities from operating and finance leases of $44 million pursuant to the new standard; ii) the derecognition of existing build-to-suit assets and liabilities of $131 million that are no longer considered to meet bui

Table of Contents

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

ld-to-suit criteria under Topic 842 and will not be recognized on the Company's balance sheet until commencement, which is expected in the second quarter of 2019; and iii) the derecognition of $49 million in lease assets and liabilities related to an existing gas pipeline lateral capital lease that no longer meets the definition of a lease under the new standard. The following table illustrates the adjustments made upon adoption of Topic 842 and the corresponding line items affected on the Company's condensed consolidated balance sheets (in millions):

	January 1, 2019 Topic 842 Adoption Adjustments			
	Increase due to existing operating and finance leases	Decrease due to build-to-suit reassessment	Decrease due to capital lease reassessment	Total Increase/(Decrease)
Assets				
Electric utility plant, net	$2	$ (131)	$ (49)	$ (178)
Other noncurrent assets	42	—	—	42
Liabilities				
Accrued expenses and other current liabilities	5	—	(2)	3
Other noncurrent liabilities	39	(131)	(47)	(139)

For new required disclosures and further information see Note 11, Leases. The transition to the new standard did not have a material impact on the Company's financial position.

On January 1, 2019 PGE adopted 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 United States Tax Cuts and Jobs Act of 2017 (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. As a result, PGE reclassified $2 million from Accumulated other compressive loss to Retained earnings during the period of adoption rather than applying the standard retrospectively. The implementation did not result in a material impact to the results of operation, financial position or statements of cash flows.

Table of Contents

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

NOTE 2: REVENUE RECOGNITION

Disaggregated Revenue

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

	Three Months Ended March 31,	
	2019	2018
Retail:		
Residential	$290	$268
Commercial	154	151
Industrial	44	44
Direct access customers	11	10
Subtotal	499	473
Alternative revenue programs, net of amortization	3	(2)
Other accrued (deferred) revenues, net[1]	7	(17)
Total retail revenues	509	454
Wholesale revenues[2]	37	28
Other operating revenues	27	11
Total revenues	$573	$493

(1) Balance primarily comprised of $6 million of amortization and $15 million of deferral for the three months ended March 31, 2019 and 2018, respectively, related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under the TCJA.
(2) Wholesale revenues include $11 million and $2 million related to electricity commodity contract derivative settlements for the three months ended March 31, 2019 and 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. Commercial customers include most businesses, small industrial companies, and public street and highway lighting accounts. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on energy use by this customer class.

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

Table of Contents

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 actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

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.

Table of Contents

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

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):

	March 31, 2019	December 31, 2018
Prepaid expenses	$ 60	$ 54
Assets from price risk management activities	33	20
Margin deposits	15	16
Other current assets	$ 108	$ 90

Electric Utility Plant, Net

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

	March 31, 2019	December 31, 2018
Electric utility plant	$ 10,416	$ 10,344
Construction work-in-progress	200	346
Total cost	10,616	10,690
Less: accumulated depreciation and amortization	(3,869)	(3,803)
Electric utility plant, net	$ 6,747	$ 6,887

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $318 million and $302 million as of March 31, 2019 and December 31, 2018, respectively. Amortization expense related to intangible assets was $16 million for the three months ended March 31, 2019 and $13 million for the three months ended March 31, 2018. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

Table of Contents

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):

	March 31, 2019		December 31, 2018	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$—	$ 74	$32	$ 99
Pension and other postretirement plans	—	219	—	222
Debt issuance costs	—	20	—	16
Trojan decommissioning activities	—	25	—	26
Other	21	42	29	38
Total regulatory assets	$21	$ 380	$61	$ 401
Regulatory liabilities:				
Asset retirement removal costs	$—	$ 991	$—	$ 979
Deferred income taxes	—	266	—	267
Trojan decommissioning activities	2	—	1	—
Asset retirement obligations	—	53	—	53
Tax Reform Deferral[(1)]	23	16	23	22
Other	16	30	12	34
Total regulatory liabilities	$41 [(2)]	$ 1,356	$36 [(2)]	$ 1,355

(1) Related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under TCJA, including interest.
(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):

	March 31, 2019	December 31, 2018
Accrued employee compensation and benefits	$ 42	$ 66
Accrued taxes payable	37	34
Accrued interest payable	44	27
Accrued dividends payable	33	34
Regulatory liabilities—current	41	36
Other	66	71
Total accrued expenses and other current liabilities	$ 263	$ 268

Credit Facilities

As of December 31, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. On January 16, 2019, PGE executed an amendment to the credit facility extending the termination date to November 14, 2022 and allowing for unlimited extensions, provided that lenders with a pro-rata share of more than 50% approve the extension request. 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 applicable credit

Table of Contents

facility. The revolving credit 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 March 31, 2019, PGE was in compliance with this covenant with a 49.3% 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 March 31, 2019, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, as of March 31, 2019, 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 $83 million were outstanding as of March 31, 2019. Letters of credit issued are not reflected on the Company’s condensed consolidated balance sheets.

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 three months ended March 31, 2019, PGE did not enter into any long-term debt transactions. Due to the upcoming repayment of long-term debt in 2019, $300 million was classified as current on the Company’s condensed consolidated balance sheets as of March 31, 2019.

On April 12, 2019, PGE issued $200 million of 4.30% Series First Mortgage Bonds due in 2049. Proceeds from the transaction were used to repay the $300 million current portion of long-term debt on April 15, 2019.

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 March 31,	
	2019	2018
Service cost	$4	$ 5
Interest cost*	8	8
Expected return on plan assets*	(10)	(10)

Amortization of net actuarial loss*	3	4
Net periodic benefit cost	$ 5	$ 7

* 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.

Table of Contents

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

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 March 31, 2019 and December 31, 2018. 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 economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the three months ended March 31, 2019 and 2018, except those presented in this note.

Table of Contents

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

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 March 31, 2019				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Cash equivalents	$82	$ —	$ —	$ —	$82
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	8	14	—	—	22
Corporate credit	—	12	—	—	12
Money market funds measured at NAV (2)	—	—	—	12	12
Non-qualified benefit plan trust: (3)					
Money market funds	2	—	—	—	2
Equity securities	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: (1) (4)					
Electricity	—	14	4	—	18
Natural gas	—	19	—	—	19
	$99	$ 59	$ 4	$ 12	$174
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$—	$ 6	$ 69	$ —	$75
Natural gas	—	30	5	—	35
	$—	$ 36	$ 74	$ —	$110

(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.

Table of Contents

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

	As of December 31, 2018				
	Level 1	Level 2	Level 3	Other [(2)]	Total
Assets:					
Cash equivalents	$112	$ —	$ —	$ —	$112
Nuclear decommissioning trust: [(1)]					
Debt securities:					
Domestic government	7	18	—	—	25
Corporate credit	—	10	—	—	10
Money market funds measured at NAV [(2)]	—	—	—	7	7
Non-qualified benefit plan trust: [(3)]					
Money market funds	2	—	—	—	2
Equity securities	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: [(1)] [(4)]					
Electricity	—	9	3	—	12
Natural gas	—	8	—	—	8
	$128	$ 45	$ 3	$ 7	$183
Liabilities:					
Interest rate swap derivatives	$—	$ 4	$ —	$ —	$4
Price risk management activities: [(1)] [(4)]					
Electricity	—	10	84	—	94
Natural gas	—	51	7	—	58
	$—	$ 65	$ 91	$ —	$156

(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 $27 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 securities holdings of such funds do not exceed 90 days and investors have the ability to redeem shares of the funds daily at their 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 NYSE.

Assets held in the Nuclear decommissioning trust (NDT) 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

18

Table of Contents

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 NYSE.

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

The NQBP trust is invested in exchange-traded government money market funds and is classified as Level 1 in the fair value hierarchy due to the availability of quoted prices in published exchanges such as NASDAQ and the NYSE. The money market fund in the NDT is valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Liabilities from interest rate swap derivatives are recorded at fair value in PGE's condensed consolidated balance sheets and consist of forward starting interest rate swap lock agreements to hedge a portion of the interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

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 to 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.

Table of Contents

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

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	Weighted Average
	(in millions)						
As of March 31, 2019:							
Electricity physical forwards	$ 4	$ 69	Discounted cash flow	Electricity forward price (per MWh)	$ 12.24	$ 75.70	$ 50.85
Natural gas financial swaps	—	5	Discounted cash flow	Natural gas forward price (per Decatherm)	1.04	4.10	1.80
	$ 4	$ 74					
As of December 31, 2018:							
Electricity physical forwards	$ 3	$ 84	Discounted cash flow	Electricity forward price (per MWh)	$ 14.60	$ 69.00	$ 45.00
Natural gas financial swaps	—	7	Discounted cash flow	Natural gas forward price (per Decatherm)	0.95	4.64	1.82
	$ 3	$ 91					

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)

Table of Contents

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

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 March 31,	
	2019	2018
Balance as of the beginning of the period	$88	$139
Net realized and unrealized (gains)/losses*	(19)	(4)
Transfers out of Level 3 to Level 2	1	(1)
Balance as of the end of the period	$70	$134

* 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 months ended March 31, 2019 and 2018, 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 March 31, 2019, the carrying amount of PGE’s long-term debt was $2,478 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,773 million. As of December 31, 2018, the carrying amount of PGE’s long-term debt was $2,478 million, net of $10 million of unamortized debt expense, and its estimated aggregate fair value was $2,760 million.

NOTE 5: RISK MANAGEMENT

Price Risk Management

PGE participates in the wholesale marketplace to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of 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 to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the

Table of Contents

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

condensed consolidated balance sheets, may include forward, futures, swaps, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the condensed consolidated statements of income and comprehensive 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):

	March 31, 2019	December 31, 2018
Current assets:		
Commodity contracts:		
Electricity	$ 17	$ 11
Natural gas	16	7
Total current derivative assets*	33	18
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Natural gas	3	1
Total noncurrent derivative assets	4	2
Total derivative assets not designated as hedging instruments	$ 37	$ 20
Total derivative assets	$ 37	$ 20
Current liabilities:		
Commodity contracts:		
Electricity	$ 12	$ 16
Natural gas	20	35
Total current derivative liabilities	32	51
Noncurrent liabilities:		
Commodity contracts:		
Electricity	63	78
Natural gas	15	23
Total noncurrent derivative liabilities	78	101
Total derivative liabilities not designated as hedging instruments	$ 110	$ 152
Total derivative liabilities	$ 110	$ 152

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

Table of Contents

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

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

	March 31, 2019		December 31, 2018	
Commodity contracts:				
Electricity	7	MWh	5	MWh
Natural gas	134	Decatherms	123	Decatherms
Foreign currency	$ 20	Canadian	$ 18	Canadian

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement gross on the condensed consolidated balance sheets. 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 March 31, 2019, and December 31, 2018, gross amounts included as Price risk management liabilities subject to master netting agreements were $71 million and $88 million, respectively, for which PGE posted collateral of $11 million in each period, which consisted entirely of letters of credit. As of March 31, 2019, of the gross amounts recognized, $69 million was for electricity and $2 million was for natural gas compared to $84 million for electricity and $4 million for natural gas recognized as of December 31, 2018.

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 comprehensive income and were as follows (in millions):

	Three Months Ended March 31,	
	2019	2018
Commodity contracts:		
Electricity	$ (24)	$ 1
Natural Gas	(25)	14

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 months ended March 31, 2019, a net gain of $49 million was offset, while $15 million of the net losses recognized in Net income were offset for the three months ended March 31, 2018.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of March 31, 2019 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2019	2020	2021	2022	2023	Thereafter	Total
Commodity contracts:							
Electricity	$ (6)	$ 5	$ 6	$ 5	$ 6	$ 41	$ 57

Natural gas	8	3	4	1	—	—	16
Net unrealized loss	$ 2	$ 8	$ 10	$ 6	$ 6	$ 41	$ 73

23

Table of Contents

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 March 31, 2019 was $107 million, for which PGE has posted $43 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at March 31, 2019, the cash requirement to either post as collateral or settle the instruments immediately would have been $91 million. As of March 31, 2019, 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:

	March 31, 2019	December 31, 2018
Assets from price risk management activities:		
Counterparty A	33 %	42 %
Counterparty B	11	15
Counterparty C	13	9
	57 %	66 %
Liabilities from price risk management activities:		
Counterparty D	62 %	56 %
	62 %	56 %

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 in the past and may enter into interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. These derivatives were designated as cash flow hedges, 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.
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 swaps are 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 March

Table of Contents

31, 2019, the Company had no outstanding interest rate swaps. As of December 31, 2018, the fair value of the interest rate swaps was a $4 million liability, which was recorded in Liabilities from price risk management activities - current on the Company's condensed consolidated balance sheets. The swaps settled at a $5 million loss in January 2019, which has been recorded in Regulatory assets - noncurrent on the condensed consolidated balance sheets.

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.

For the three months ended March 31, 2019, unvested performance-based restricted stock units and related dividend equivalent rights of 263 thousand shares were excluded from the dilutive calculation because the performance goals had not been met, with 230 thousand shares excluded for the three months ended March 31, 2018.

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 March 31,	
	2019	2018
Weighted-average common shares outstanding—basic and diluted	89,309	89,160

Table of Contents

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

NOTE 7: SHAREHOLDERS' EQUITY

The activity in equity during the three-month periods ended March 31, 2019 and 2018 was as follows (dollars in millions, except per share amounts):

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balances as of December 31, 2018	89,267,959	$1,212	$ (7)	$1,301	$2,506
Issuances of shares pursuant to equity-based plans	88,352	—	—	—	—
Other comprehensive income	—	—	1	—	1
Dividends declared ($0.3625 per share)	—	—	—	(32)	(32)
Net income	—	—	—	73	73
Reclassification of stranded tax effects due to Tax Reform	—	—	(2)	2	—
Balances as of March 31, 2019	89,356,311	$1,212	$ (8)	$1,344	$2,548
Balances as of December 31, 2017	89,114,265	$1,207	$ (8)	$1,217	$2,416
Issuances of shares pursuant to equity-based plans	99,854	—	—	—	—
Stock-based compensation	—	(1)	—	—	(1)
Dividends declared ($0.3400 per share)	—	—	—	(30)	(30)
Net income	—	—	—	64	64
Balances as of March 31, 2018	89,214,119	$1,206	$ (8)	$1,251	$2,449

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. 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.

Table of Contents

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

PGE evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) 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. PGE has been included among more than one hundred Potentially Responsible Parties (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 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 in January 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.

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 the final selection of a proposed remedy by the EPA, 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 that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. However, based on the above facts and remaining uncertainties, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that represents PGE’s portion of the liability to clean-up Portland Harbor, although such costs could be material to PGE’s financial position.

In cases in which injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for such damages at such sites, which are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. The Portland Harbor NRD trustees consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State of Oregon, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, and the Nez Perce Tribe.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. 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.

The impact of such costs to the Company’s results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) Mechanism. As approved by the OPUC in 2017, the PHERA allows the Company to defer and recover incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as insurance recoveries, and if necessary through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE’s actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE’s most recent general rate case. PGE’s results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company plans to seek recovery of any costs resulting from EPA’s determination of liability for Portland Harbor through proceeds from third parties such as claims under insurance policies and, if necessary, recovery in customer prices. At this time, PGE is not recovering any Portland Harbor cost from the PHERA mechanism through customer prices.

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

Table of Contents

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 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, 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 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement on the class action proceedings and, 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

In August 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 sought injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claimed PGE had 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 alleged the violations were 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 alleged that PGE's operation of the SWW had caused the above-referenced violations of the CWA, which in turn had degraded the fish and wildlife habitat of the Deschutes River below the Project and harmed the economic and personal interests of DRA's members and supporters.

In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the Confederated Tribes of Warm Springs (CTWS), which co-owns the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

Table of Contents

On August 3, 2018, the Judge denied DRA’s motions for partial summary judgment and granted PGE’s and CTWS’s cross-motions for summary judgment, ruling in favor of PGE and CTWS. The Judge found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

On October 17, 2018, DRA filed an appeal to the Ninth Circuit Court of Appeals. Briefing is scheduled to begin in August 2019.

The Company cannot predict the outcome of this matter or determine the likelihood of whether the outcome 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 March 31, 2019, 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.

Table of Contents

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

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 reflected in the following table:

	Three Months Ended March 31,	
	2019	2018
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits*	(12.7)	(18.0)
State and local taxes, net of federal tax benefit	6.5	6.5
Flow through depreciation and cost basis differences	1.3	1.0
Excess deferred tax amortization	(3.7)	—
Other	0.7	0.6
Effective tax rate	13.1 %	11.1 %

* Federal tax credits consists of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. PTCs are earned based on a per-kilowatt hour rate and, as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. PTCs are generated for 10 years from the in-service dates of the corresponding facilities. PGE's PTC generation ends at various dates through 2024.

On February 14, 2018, the FASB issued ASU 2018-02 that allows entities subject to FASB requirements to reclassify stranded tax effects resulting from the TCJA from accumulated other comprehensive income (AOCI) to retained earnings. Stranded tax effects are the result of certain items that were recorded in AOCI, net of tax using a historical 35% federal tax rate, and the removal of those items from AOCI using the current 21% tax rate. Pursuant to ASU 2018-02, PGE reclassified $2 million of stranded tax effects from Accumulated other comprehensive loss to Retained earnings for the period ended March 31, 2019.

Carryforwards

Federal tax credit carryforwards as of March 31, 2019 and December 31, 2018 were $59 million and $52 million, respectively. These credits consist of PTCs, which will expire at various dates through 2039. PGE believes that it is more likely than not that its deferred income tax assets as of March 31, 2019 will be realized; accordingly, no valuation allowance has been recorded. As of March 31, 2019, and December 31, 2018, PGE had no unrecognized tax benefits.

NOTE 11: LEASES

PGE determines if an arrangement is a lease at inception and whether the arrangement is classified as an operating or finance lease. At commencement of the lease, PGE records a right-of-use (ROU) asset and lease liability in the condensed consolidated balance sheets based on the present value of lease payments over the term of the arrangement. ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent PGE's obligation to make lease payments arising from the lease. If the implicit rate is not readily determinable in the contract, PGE uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Contract terms may include options to extend or terminate the lease, and when the Company deems it is reasonably certain that PGE will exercise that option it is included in the ROU asset and lease liability. Operating leases will reflect lease expense on a straight-

Table of Contents

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

line basis, while finance leases will result in the separate presentation of interest expense on the lease liability and amortization expense of the right-of-use asset. Any material differences between expense recognition and timing of payments will be deferred as a regulatory asset or liability in order to match what is being recovered in customer prices.

PGE does not record leases with a term of 12-months or less in the condensed consolidated balance sheet. Total short-term lease cost for the three months ended March 31, 2019 is immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

The Company's leases relate primarily to the use of land, support facilities, and power purchase agreements that rely on identified plant. Variable payments are generally related to power purchase agreements for components dependent upon energy production, and are not included in the determination of the present value of lease payments.

The components of lease cost were as follows (in millions):

	Three Months Ended March 31, 2019
Operating lease cost	$ 1
Variable lease cost	$ 9

Supplemental information related to amounts and presentation of leases in the condensed consolidated balance sheets is presented below (in millions):

	Balance Sheet Classification	March 31, 2019
Operating Leases:		
Operating lease right-of-use assets	Other noncurrent assets	$ 41
Current operating lease liabilities	Accrued expenses and other current liabilities	5
Noncurrent operating lease liabilities	Other noncurrent liabilities	36
Total operating lease liabilities		$ 41
Finance Leases:		
Finance lease right-of-use assets	Electric utility plant, net	$ 2
Current finance lease liabilities	Accrued expenses and other current liabilities	—
Noncurrent finance lease liabilities	Other noncurrent liabilities	2
Total finance lease liabilities		$ 2

Table of Contents

Lease term and discount rates were as follows:

	March 31, 2019
Weighted Average Remaining Lease Term	
Operating leases	30 years
Finance leases	4 years
Weighted Average Discount Rate	
Operating leases	3.8 %
Finance leases	3.4 %

As of March 31, 2019, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2019	$ 4	$ —
2020	5	—
2021	5	1
2022	5	1
2023	5	—
Thereafter	53	—
Total lease payments	$ 77	$ 2
Less imputed interest	(36)	—
Total	$ 41	$ 2

Supplemental cash flow information related to leases was as follows (in millions):

	Three Months Ended March 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	$ 1

As of March 31, 2019, PGE has an additional operating lease for a power purchase agreement and a finance lease for a gas storage agreement, neither of which have commenced, with an estimated present value of future lease payments of $15 million and $130 million, respectively. These operating and finance leases are expected to commence in 2019 with lease terms of five and 30 years, respectively.

Table of Contents

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

2018 Lease Obligations

As of December 31, 2018, and pursuant to historical lease accounting under Topic 840, PGE's estimated future minimum lease payments pursuant to capital, build-to-suit, and operating leases for the following five years and thereafter are as follows (in millions):

	Future Minimum Lease Payments		
	Capital Leases	Build-to-Suit	Operating Leases
2019	$6	$ 11	$ 4
2020	6	14	5
2021	6	13	5
2022	6	13	6
2023	5	13	7
Thereafter	67	225	97
Total minimum lease payments	96	$ 289	$ 124
Less imputed interest	(47)		
Present value of net minimum lease payments	49		
Less current portion	(2)		
Noncurrent portion	$47		

Capital Leases—PGE entered into agreements to purchase natural gas transportation capacity via a 24-mile natural gas pipeline, Carty Lateral, that was constructed to serve the Carty facility. The Company has entered into a 30-year agreement to purchase the entire capacity of Carty Lateral, which is approximately 175,000 decatherms per day. At the end of the initial contract term, the Company has the option to renew the agreement in continuous three-year increments with at least 24 months prior written notice.

As of December 31, 2018, a capital lease asset of $57 million and accumulated amortization of such assets of $8 million was reflected within Electric utility plant, net in the condensed consolidated balance sheets. The present value of the future minimum lease payments due under the agreement included $2 million within Accrued expenses and other current liabilities and $47 million in Other noncurrent liabilities on the condensed consolidated balance sheets. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Amortization of the leased asset of $3 million and interest expense of $4 million was recorded to Purchased power and fuel expense in the consolidated statements of income through December 31, 2018 and 2017. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE derecognized the capital lease obligation and related capital lease asset as it no longer met the definition of a lease.

Build-to-suit—PGE entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-miles of pipeline, which are collectively designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, in September 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates construction will be completed during the second quarter of 2019, at a cost of approximately $149 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 recorded $131 million to Construction work-in-progress within Electric utility plant, net and a corresponding liability for the same amount to Other noncurrent liabilities in the condensed consolidated balance sheets as of December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842,

Table of Contents

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

PGE derecognized the build-to-suit assets and liabilities as they are no longer considered to meet the build-to-suit criteria under the new standard.

The table above reflects PGE's estimated future minimum lease payments pursuant to the agreement based on estimated costs.

Operating leases—PGE has various operating leases associated with leases of land, support facilities, and power purchase agreements that rely on identified plant that expire in various years, extending through 2096. Rent expense was $7 million in 2018 and $9 million in 2017. Contingent rents related to power purchase agreements was $14 million in 2018.

Sublease income was $4 million in 2018 and 2017.

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 i 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, legislative actions, 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;

Table of Contents

- 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 any such 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 ineffective execution 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 may 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, and transitions in senior management;

- new federal, state, and local laws that could have adverse effects on operating results;
- 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, 2018, 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 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.

PGE's 2016 Integrated Resource Plan (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, which led to the agreement for the Wheatridge Renewable Energy Facility (Wheatridge), 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 Company's resource planning, see "Integrated Resource Plan" in this Overview section of Item 2.

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 local economy. The Company is also working to advance transportation electrification, with projects to expand and increase access to electric vehicle charging stations, and partnering with local mass transit agencies to transition to a greater use of electric vehicles.

Building a smarter, more resilient grid is essential to affordably delivering the clean energy future that customers want. This requires embracing new technologies, continuing to modernize the Company's existing infrastructure, and utilizing the new customer information system to create a foundation to integrate emerging technologies. PGE's capital requirements contemplate the impact of making investments in new, renewable resource generation and energy storage facilities, as well as improvements to its transmission, distribution, and information technology infrastructure.

Oregon's Clean Electricity and Coal Transition Plan, enacted in 2016, set a benchmark for how much electricity must come from renewable sources like wind and solar (50 percent by 2040) and requires the elimination of coal from Oregon utility customers' energy supply by 2035. Local governments are also enacting clean energy policy goals. The 2019 Oregon legislative session has introduced proposed legislation that would implement a carbon cap and trade program. For more information on this initiative, see "Oregon Legislative Initiatives" in the Legal, Regulatory and Environmental section of this Item 2.

In June 2017, Oregon’s most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE’s service area, including the cities of Milwaukie and Hillsboro, are considering similar goals. These commitments reflect the values held by customers. As a result, the

Table of Contents

Company is in the process of implementing a Green Tariff program to address this market. For more information on this program, see “Green Tariff” in the Legal, Regulatory and Environmental section of this Item 2.

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 orders issued in 2017, the OPUC acknowledged PGE’s 2016 IRP, enabling the Company to, among other things, finalize agreements to purchase additional annual and seasonal capacity as well as pursue renewable energy and energy storage as described in the paragraphs that follow.

Renewable Energy—In May 2018, the Company issued a request for proposals seeking to procure approximately 100 MWa of qualifying renewable resources. The prevailing bid, Wheatridge, will be an energy facility in eastern Oregon combining 300 megawatts (MW) of wind generation with 50 MW of solar generation and 30 MW of battery storage.

Wheatridge will consist of 120 wind turbines manufactured by GE Renewable Energy, Inc. PGE will own 100 MW of the wind resource with an investment of approximately $160 million. Subsidiaries of NextEra Energy Resources, LLC plan to build and operate the facility and will own the balance of the 300 MW wind resource, along with the solar and battery components, and sell their portion of the output to PGE under 30-year power purchase agreements. PGE has the option to purchase the underlying assets of the power purchase agreement on the 12th anniversary of the commercial operation date of the wind facility for the greater of the book value or fair market value as determined on the date of the purchase option.

The wind component of the facility is expected to be operational by December 2020 and qualify for federal production tax credits (PTCs) at the 100 percent level. Construction of the solar and battery components is planned for 2021 and is expected to qualify for federal investment tax credits. Any tax credits will help reduce the cost of the project and thus reduce costs to PGE’s customers.

The agreements signed by PGE and subsidiaries of NextEra Energy Resources, LLC will be subject to prudency review on customers’ behalf by the OPUC.

Energy Storage—Pursuant to the 2016 IRP, PGE filed an energy storage proposal that called for 39 MW of storage to be developed over the next several years at various locations across the grid. In August 2018, the OPUC issued an order that outlined an agreed approach to the development of five energy storage projects by PGE with an expected capital cost of approximately $45 million.

2019 IRP—In preparation for its 2019 IRP, PGE conducted an informal public process throughout the past year. The Company has presented multiple enabling studies to support the 2019 IRP, including a:

- Decarbonization Study evaluating the potential impacts of reducing economy-wide greenhouse gas emissions in the PGE service area by 80% by 2050;
- Market Capacity Study evaluating the potential for shifting regional loads and resources to impact the availability of market capacity in the Pacific Northwest over time;
- Distributed Resource and Flexible Load Study, which provided a holistic view of potential Distributed Energy Resource adoption, electric vehicle adoption, and demand response and flexible load program participation among PGE customers; and
- Supply-Side Option Study that provided costs and performance characteristics for supply-side renewables, storage, and thermal resources.

PGE is using the results of the studies and continuing to engage stakeholders in the informal public process to shape the 2019 IRP along with a proposed action plan, which the Company expects to file with the OPUC in the summer of 2019.

Capital Requirements and Financing—The Company expects 2019 capital expenditures to total $600 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 2019, which is expected to range from $550 million to $600 million, and the issuance of debt securities of up to $450 million. For additional information, see “Liquidity” and “Debt and Equity Financings” in the Liquidity and Capital Resources section of this Item 2.

Operating Activities—In combination with electricity provided by its own generation portfolio, PGE purchases and sells electricity in the wholesale market to meet its retail load requirements and balance its energy supply with customer demand. PGE participates in the California Independent System Operator’s Energy Imbalance Market (western EIM), which allows the Company to integrate more renewable energy into the grid by better matching the variable output of renewable resources. PGE also purchases natural gas in the United States and Canada to fuel its generation portfolio and sells excess gas back into the wholesale market.

The Company generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers. The impact of seasonal weather conditions on demand for electricity can cause the Company’s revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE has experienced its highest average MWh deliveries and retail energy sales during the winter heating season, although peak deliveries have increased 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. 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 three months ended March 31, 2019, increased 4.3% compared with the three months ended March 31, 2018, as illustrated in the table below. This increase was primarily driven by cooler temperatures in the 2019 period, which influenced usage in the residential and commercial classes, and continued growth in demand for energy deliveries from the Company’s industrial customers.

Residential energy deliveries increased 5.8% in the first quarter of 2019 and commercial deliveries were up 2.6% compared with the first quarter of 2018 with the increases driven primarily by the effect of the temperature differences. Energy deliveries to industrial customers were up 4.2% for the quarter compared with the prior year.

In the first quarter of 2019, customer demand was influenced by cooler than average temperatures during the heating season. Heating degree-days, an indication of the extent to which customers are likely to have used electricity for heating, were 13% above the first quarter of 2018, which was 3% below the historical average. See “Revenues” in the Results of Operations section of this Item 2 for further information on heating degree-days.

Although total retail energy deliveries for the three months ended March 31, 2019 increased, after adjusting for the effects of weather, total energy deliveries declined 0.3% from the same period of 2018. Decreased average usage per customer driven by energy efficiency and conservation efforts continues to be partially offset by growth in customer count and increased deliveries to high tech manufacturing customers. The financial effects of such energy efficiency and conservation 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

39

Table of Contents

the corresponding energy deliveries, for the periods indicated:

	Three Months Ended March 31,					
	2019		2018		% Increase (Decrease) in Energy Deliveries	
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*		
Residential	776,067	2,256	768,886	2,133	5.8	%
Commercial (PGE sales only)	109,750	1,631	106,730	1,597	2.1	%
Direct Access	563	164	530	152	7.9	%
Total Commercial	110,313	1,795	107,260	1,749	2.6	%
Industrial (PGE sales only)	199	708	206	680	4.1	%
Direct Access	68	360	67	345	4.3	%
Total Industrial	267	1,068	273	1,025	4.2	%
Total (PGE sales only)	886,016	4,595	875,822	4,410	4.2	%
Total Direct Access	631	524	597	497	5.4	%
Total	886,647	5,119	876,419	4,907	4.3	%

* 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 13% of PGE’s total retail energy deliveries for the first three months of 2019. Actual energy deliveries to Direct Access customers represented 10% of the Company’s total retail energy deliveries for the first three months of 2019 and 11% for the full year 2018. During 2018, the OPUC created a New Large Load Direct Access program, capped at approximately 120 MWa, for unplanned, large, new loads and large load growth at existing sites. The Company continues to work through the regulatory process to implement the new program.

Power Operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. As a result, the amount of power generated and purchased in the wholesale market to meet the Company’s retail load requirement can vary from period to period.

Plant availability is impacted by planned maintenance and forced, or unplanned, outages, during which the respective plant is unavailable to provide power. Availability of all the plants PGE operates was 98% and 82% during the three months ended March 31, 2019 and 2018, respectively. Plant availability of Colstrip, which PGE does not operate, was 93% and 98% during the three months ended March 31, 2019 and 2018, respectively.

During the three months ended March 31, 2019, the Company’s generating plants provided 82% of its retail load requirement compared with 70% in the three months ended March 31, 2018. The increase in the proportion of power generated to meet the Company’s retail load requirement was largely due to PGE effectively dispatched its lowest-cost resources in a challenged market, resulting in a 22% increase in the power generated by the Company’s resources during the three months ended March 31, 2019 compared to the three months ended March 31, 2018.

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 three months ended March 31, 2019, energy received from these hydro resources decreased by 36% compared to the three months ended March 31, 2018. Energy received from these hydro resources fell short of the projected levels included in PGE's AUT by 22% for the three months ended March 31, 2019 and exceeded by 11% for the three months ended March 31, 2018, and provided 13% of the Company's retail load requirement for the three months ended March 31, 2019 and 20% for the three months ended March 31, 2018. Energy received from hydro resources is expected to range from 0% to 5% below levels projected in the AUT for 2019.

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 three months ended March 31, 2019, energy received from these wind generating resources decreased 55% compared to the three months ended March 31, 2018, resulting in the Company incurring additional replacement costs, as well as generating less Production Tax Credits (PTCs) than what was estimated in customer prices. Energy received from these wind generating resources fell short of projections in PGE's AUT by 43% for the three months ended March 31, 2019 and exceeded projections in the AUT by 16% for the three months ended March 31, 2018, and provided 4% and 10% of the Company's retail load requirement during the three months ended March 31, 2019 and 2018, respectively. Energy received from wind resources is expected to fall short of levels projected in the AUT for 2019 by up to 10%.

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 comprehensive income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income and comprehensive income. 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 and comprehensive income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense.

For the three months ended March 31, 2019, actual NVPC was $12 million above baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2019 is currently estimated to be below the baseline, but within the established deadband range. Accordingly, no estimated refund to customers is expected under the PCAM for 2019.

For the three months ended March 31, 2018, actual NVPC was $11 million below baseline NVPC. For the year ended December 31, 2018, actual NVPC was $3 million below baseline NVPC, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded pursuant to the PCAM for 2018.

Fuel Supply —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

Table of Contents

estimates construction will be completed during the second quarter of 2019, at a cost of approximately $149 million. Upon completion of the facility, the lease will commence and PGE will record a finance lease ROU asset and lease liability on its consolidated balance sheets.

The Colstrip co-owners currently obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The company that owns and operates the mine declared bankruptcy in the fourth quarter of 2018. Debtors in the bankruptcy proceeding filed notice on January 19, 2019 of their intention to reject the co-owners' current coal supply contract, which currently extends through December 31, 2019. The co-owners filed objections to the proposed rejection of the coal supply contract, and on February 22, 2019, the debtors filed an amended plan of reorganization in which they withdrew the proposal to reject the contract. The court approved the debtors' amended plan of reorganization on March 2, 2019 which allows the coal supply contract to remain in effect through 2019.

Legal, Regulatory, and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the financial position, 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.

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

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 accelerate recovery of PGE's investment in the Colstrip facility from 2042 to 2030.

Other 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 the Company's renewable adjustment clause mechanism (RAC) filings.

The Company continues to consider the potential impacts and incorporate the effects of the legislation into its IRP process.

SB 978—In 2017, Senate Bill 978 (SB 978) directed the OPUC to investigate and provide a report to the Oregon legislature on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. In its September 14, 2018 report, the OPUC committed to:

- explore performance-based ratemaking and other regulatory tools to align utility incentives with customer goals, industry trends, and statewide goals;
- cooperate with other states to support and explore development of an organized, regional market;
- develop a strategy for low income and environmental justice groups' engagement and inclusion in OPUC processes that will carry forward beyond the SB 978 proceeding; and

Table of Contents

improve the OPUC's regulatory tools to value system costs and benefits, which enables customer choice and a strong utility system.

The OPUC also stated that it would collaborate with the legislature and stakeholders to make progress on climate change, noting that their authority is limited to that of an economic regulator. The legislature may address the limitation identified by the OPUC for direct authority to address climate change through comprehensive cap and trade legislation during the 2019 legislative session.

HB 2020—In the 2019 session, State of Oregon legislators are giving consideration to a proposal called the Oregon Climate Action Program, House Bill 2020 (HB 2020), which is intended to reduce greenhouse gas emissions that contribute to climate change. Among other things, the legislation, as proposed, would:

- require a program to place a cap on greenhouse gas emissions and provide a market-based mechanism for covered entities to demonstrate compliance with the program (a cap and trade program);
- modify statewide greenhouse gas emissions reduction goals by making them more stringent and the basis for the new mandatory emissions cap;
- provide direct allocation of allowances to regulated electric utilities to protect customers from compliance costs; and
- authorize the OPUC to allow tariffs for, or reflect in customer prices amounts of, programs that enable public utilities to assist low-income residential customers.

The Company continues to monitor the proposed legislation as it progresses through the 2019 legislative session.

Green Tariff —In the first quarter 2019, the OPUC approved PGE's Green Tariff program, which allows for the procurement of new renewable resources and will provide business customers access to bundled renewable energy from those new resources. Through this voluntary tariff, the Company seeks to align sustainability goals, cost and risk management, reliable integrated power, and a cleaner energy system. PGE has structured the tariff so that Green Tariff subscribers continue to pay the existing cost of service tariff rate plus the rate under the renewable energy option tariff. This structure is intended to avoid stranded cost and cost shifting. Renewable power provided under the tariff will be procured through power purchase agreements.

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 quarter of 2019 compared to the first quarter of 2018, 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 2018, the 2019 GRC included a final projected increase in power costs for 2019, and a corresponding increase in annual revenue requirement, of $25 million from 2018 levels, which is reflected in customer prices effective January 1, 2019.

Under the PCAM for 2018, 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 2018 during the second half of 2019 with a decision expected in the fourth quarter 2019.

Renewable Resource Costs—Pursuant to the RAC, PGE can recover in customer prices the prudently incurred costs of renewable resources. In the 2019 GRC Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings, under certain conditions. The Company may submit a filing to the OPUC by April 1st each year. No significant filings have been submitted under the RAC during 2019 or 2018.

Table of Contents

Decoupling—The decoupling mechanism, which the OPUC has extended through 2022, 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 collection of the $3 million recorded in 2016 that resulted from variances between actual weather-adjusted use per customer and that projected in the 2016 GRC, occurred during 2018. The Company recorded an estimated collection of $11 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. Collection from customers for the 2017 year is expected to occur over a one-year period, which began January 1, 2019. The Company recorded an estimated collection of $2 million during the year ended December 31, 2018, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2018 GRC. Any collection from customers, as approved, for the 2018 year is expected to occur over a one-year period, which would begin January 1, 2020.

Collections under the decoupling mechanism are subject to an annual limitation of 2% of the applicable rate schedule, which was $18 million for 2018.

The Company deferred an estimated collection of $8 million during the three months ended March 31, 2019, which resulted from projections established in the 2019 GRC. Any collection from (or refund to) customers for the 2019 year is expected to occur over a one-year period, which would begin January 1, 2021.

Storm Restoration Costs—Beginning in 2011, the OPUC authorized the Company to collect annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. Under the 2019 GRC, the annual collection amount increased to $4 million beginning in 2019.

Due to a series of storm events in the first half of 2017, the Company exhausted the 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 amount collected in 2017. During 2016, due to excessive storm restoration costs, PGE had exhausted the available reserve at the end of the year.

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. An OPUC decision on the application remains pending. The Company is unable to predict how the OPUC will ultimately rule on this application or state with any certainty 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. The OPUC, in its decision on the Company's 2019 GRC, directed OPUC Staff to bring this matter before the OPUC within 90 days of the issuance of the decision on the 2019 GRC. The OPUC has opened a docket in this matter and established a procedural schedule that concludes with closing briefs June 27, 2019, with a decision likely during the third quarter of 2019.

Portland Harbor Environmental Remediation Account Mechanism—The Company's environmental recovery mechanism allows the Company to defer and recover incurred environmental expenditures related to Portland Harbor through a combination of third-party proceeds, such as insurance recoveries, and if necessary through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses

Table of Contents

related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent general rate case. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company plans to seek recovery of any costs resulting from EPA's determination of liability for Portland Harbor through proceeds from third parties such as claims under insurance policies and, if necessary, recovery in customer prices. At this time, PGE is not recovering any Portland Harbor cost from the PHERA mechanism through customer prices.

Capital Project Deferral—In the second quarter of 2018, PGE placed into service a new customer information system at a total cost of $152 million. Consistent with agreements reached with stakeholders in the Company's 2019 General Rate Case, the Company's capital cost of the asset is included in rate base and customer prices as of January 1, 2019.

Consistent with past regulatory precedent, on May 11, 2018, the Company submitted an application to the OPUC to defer the revenue requirement associated with this new customer information system from the time the system went into service through the end of 2018. As a result, PGE began deferring its incurred costs, primarily related to depreciation and amortization, of the new customer information system once it was placed in service.

In November 2017, the OPUC opened docket UM 1909 to conduct an investigation of the scope of its authority under Oregon law to allow the deferral of costs related to capital investments for later inclusion in customer prices. On October 29, 2018, the OPUC issued Order 18-423 (Order) concluding that the OPUC lacks authority under Oregon law to allow deferrals of any costs related to capital investments. In the Order, the OPUC acknowledged that this decision is contrary to its past limited practice of allowing deferrals related to capital investments and will require adjustments to its regulatory practices. The OPUC directed its Staff to meet with the utilities and stakeholders to address the full implications of this decision, and to propose recommendations needed to implement this decision consistent with the OPUC's legal authority and the public interest.

In response to the Order, PGE and other utilities filed a motion for reconsideration and clarification, which was denied. On April 19, 2019, PGE and the other utilities filed a petition for judicial review of the OPUC Order with the Oregon Court of Appeals. PGE believes that the costs incurred to date associated with the customer information system were prudently incurred and has not withdrawn its deferral application to recover the revenue requirement of this capital project.

During 2018, PGE deferred a total of $12 million related to the project. However, the Order has impacted the probability of recovery of the customer information system deferral and, as such, the Company has recorded a reserve for the full amount of the capital deferral. The reserve was recognized as a charge to the results of operations in 2018. Any amounts that may ultimately be approved by the OPUC in subsequent proceedings would be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC.

Critical Accounting Policies

The Company's critical accounting policies are outlined in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on February 15, 2019.

Table of Contents

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, 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 March 31,			
	2019		2018	
Total revenues	$573	100%	$493	100 %
Purchased power and fuel	179	31	130	26
Gross margin[1]	394	69	363	74
Other operating expenses:				
Generation, transmission and distribution	77	13	69	14
Administrative and other	71	12	69	14
Depreciation and amortization	101	18	92	19
Taxes other than income taxes	34	6	33	7
Total other operating expenses	283	49	263	54
Income from operations	111	19	100	20
Interest expense[2]	32	6	31	6
Other income:				
Allowance for equity funds used during construction	3	1	4	1
Miscellaneous income (expense), net	2	—	(1)	—
Other income, net	5	1	3	1
Income before income tax expense	84	15	72	15
Income tax expense	11	2	8	2
Net income	$73	13 %	$64	13 %

(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 and $2 million for the three months ended March 31, 2019 and 2018, respectively.

Net income was $73 million, or $0.82 per diluted share, for the three months ended March 31, 2019, compared with $64 million, or $0.72 per diluted share, for the three months ended March 31, 2018. The increase was primarily driven by a combination of colder temperatures and continued strength in the industrial sector resulting in higher energy deliveries and an increase in retail revenue. Partially offsetting the revenue increase were higher prices for purchased power and natural gas due to cold temperatures that increased regional demand, lower than average wind and hydropower production, and pipeline maintenance that limited natural gas supply. Net income benefited from the absence of costs associated with Carty litigation in 2019 that was present in 2018. The Company experienced higher plant maintenance, labor, and employee benefit expenses, as well as plant depreciation and software amortization in 2019.

Table of Contents

Three Months Ended March 31, 2019 Compared with the Three Months Ended March 31, 2018

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

	Three Months Ended March 31,			
	2019		2018	
Revenues (dollars in millions):				
Retail:				
Residential	$290	50 %	$268	54 %
Commercial	154	27	151	31
Industrial	44	8	44	9
Direct Access	11	2	10	2
Subtotal	499	87	473	96
Alternative revenue programs, net of amortization	3	1	(2)	—
Other accrued (deferred) revenues, net	7	1	(17)	(4)
Total retail revenues	509	89	454	92
Wholesale revenues	37	6	28	6
Other operating revenues	27	5	11	2
Total revenues	$573	100 %	$493	100 %
Energy deliveries (MWh in thousands):				
Retail:				
Residential	2,256	39 %	2,133	37 %
Commercial	1,631	28	1,597	27
Industrial	708	12	680	12
Subtotal	4,595	79	4,410	76
Direct access:				
Commercial	164	3	152	3
Industrial	360	6	345	6
Subtotal	524	9	497	9
Total retail energy deliveries	5,119	88	4,907	85
Wholesale energy deliveries	674	12	874	15
Total energy deliveries	5,793	100 %	5,781	100 %
Average number of retail customers:				
Residential	776,067	88 %	768,886	88 %
Commercial	109,750	12	106,730	12
Industrial	199	—	206	—
Direct access	631	—	597	—
Total	886,647	100 %	876,419	100 %

Total revenues for the three months ended March 31, 2019 increased $80 million, or 16%, compared with the three months ended March 31, 2018, consisting primarily of a $55 million increase in Total retail revenues, along with a $9 million increase in Wholesale revenues and $16 million in Other operating revenues.

47

Table of Contents

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

- $20 million resulted from higher 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 cooler temperatures in the first quarter of 2019 than experienced in 2018, which saw near average temperatures, produced higher deliveries;

- $16 million due to recording during 2018 of 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. The reduction in revenues was offset with lower income tax expense, resulting in no overall net income impact; and
- $6 million from the results of the decoupling mechanism. An estimated $8 million collection was recorded in 2019, as opposed to an estimated $3 million refund in 2018, net of amortization of prior deferrals; and
- $8 million increase in revenues as a result of price changes due primarily to the annual AUT update and the decoupling mechanism.

Total heating degree-days for the three months ended March 31, 2019 were 13% above those for the three months ended March 31, 2018 and 9% above average. The following table indicates the number of heating degree-days for the three months ended March 31, 2019 and 2018, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		
	2019	2018	Avg.
January	670	595	739
February	760	625	581
March	562	546	509
Year-to-date	1,992	1,766	1,829
Increase/(decrease) from the 15-year average	9 %	(3)%	

Wholesale revenues for the three months ended March 31, 2019 increased $9 million, or 32%, from the three months ended March 31, 2018, with the increase comprised of $16 million related to a 73% increase in average wholesale sales prices partially offset by $6 million related to a 23% decrease in wholesale sales volumes. Higher, and considerably more volatile, wholesale power prices resulted from the high retail demand and natural gas supply constraints in the region.

Other operating revenues for the three months ended March 31, 2019 increased $16 million from the three months ended March 31, 2018 driven primarily by the sale of natural gas in excess of amounts needed for the Company’s generation portfolio back into the wholesale market during periods of high gas prices.

Purchased power and fuel expense increased $49 million, or 38%, for the three months ended March 31, 2019 compared with the three months ended March 31, 2018. This change consisted of $60 million related to an increase in the average variable power cost per MWh, and an $11 million decrease related to total system load.

The $60 million increase in the average variable power cost to $31.59 per MWh in the three months ended March 31, 2019 from $22.96 per MWh in the three months ended March 31, 2018, was driven primarily by a 114% increase in the average variable power cost per MWh for purchased power. For the three months ended March 31, 2019, the region faced a variety of factors that increased both the demand and the price per MWh for the period, including; colder temperatures, lower hydro and wind production, and limited natural gas supply due to pipeline maintenance. This was partially offset as the Company effectively dispatched PGE-owned generating facilities at lower prices.

Table of Contents

The $11 million decrease related to total system load was driven primarily by a 23% decrease in wholesale deliveries, partially offset by slightly higher retail energy deliveries.

The sources of energy for PGE's total system load, as well as its retail load requirement, were as follows:

	Three Months Ended March 31,			
	2019		2018	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Natural gas	2,168	38%	1,863	33%
Coal	1,335	24	545	10
Total thermal	3,503	62	2,408	43
Hydro	377	7	472	8
Wind	212	4	475	8
Total generation	4,092	73	3,355	59
Purchased power:				
Term	1,258	22	1,747	31
Hydro	247	4	506	9
Wind	Repurchase of common stock			

(4,398
)

(331,708
)

(331,708
)
Dividends paid

(122,272
)

(122,272
)
Change in fair value of interest rate swaps, net of taxes

1,392

1,392

Net income

437,120

437,120

Stockholders' equity at
December 31, 2016
130,795

1,360

671,515

(1,761,498
)

1,392

2,540,449

1,453,218

Issuance of common stock under employee stock purchase plan
83

1

4,282

4,283

Exercise of stock options and restricted stock units
349

2

12,045

12,047

Share-based compensation

29,202

29,202

Repurchase of shares to satisfy tax obligations

(816
)

(816
)
Repurchase of common stock
(5,924
)

(369,403
)

(369,403
)
Dividends paid

(133,828
)

(133,828
)
Change in fair value of interest rate swaps, net of taxes

1,371

1,371

Net income

422,599

422,599

Reclassification of stranded tax effects (ASU 2018-02)

595

(595
)

—

Stockholders' equity at
December 30, 2017
125,303

1,363

716,228

(2,130,901
)

3,358

2,828,625

1,418,673

Issuance of common stock under employee stock purchase plan
78

1

4,359

4,360

Exercise of stock options and restricted stock units
1,434

11

75,272

75,283

Share-based compensation

28,921

28,921

Repurchase of shares to satisfy tax obligations

(1,367
)

(1,367
)
Repurchase of common stock
(4,987
)

(349,776
)

(349,776
)
Dividends paid

(147,087
)

(147,087
)
Change in fair value of interest rate swaps, net of taxes

456

456

Net income

532,357

532,357

Stockholders' equity at
December 29, 2018
121,828

$
1,375

$
823,413

$
(2,480,677
)

$
3,814

$
3,213,895

$
1,561,820

The accompanying notes are an integral part of these Consolidated Financial Statements.

Index

TRACTOR SUPPLY COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Fiscal Year		
	2018 (52 weeks)	2017 (52 weeks)	2016 (53 weeks)
Cash flows from operating activities:			
Net income	$532,357	$422,599	$437,120
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	177,351	165,834	142,958
(Gain) / loss on disposition of property and equipment	(567)	460	579
Share-based compensation expense	28,921	29,202	23,554
Deferred income taxes	11,887	26,724	9,976
Change in assets and liabilities:			
Inventories	(136,334)	(83,552)	(67,650)
Prepaid expenses and other current assets	(26,195)	2,305	1,782
Accounts payable	43,413	57,046	82,477
Accrued employee compensation	22,373	6,427	(18,237)
Other accrued expenses	36,406	(10,338)	20,368
Income taxes	(8,355)	4,210	11,787
Other	13,137	10,533	5,997
Net cash provided by operating activities	694,394	631,450	650,711
Cash flows from investing activities:			
Capital expenditures	(278,530)	(250,401)	(226,017)
Proceeds from sale of property and equipment	2,216	11,220	362
Acquisition of Petsense, net of cash acquired	—	1,225	(143,610)
Net cash used in investing activities	(276,314)	(237,956)	(369,265)
Cash flows from financing activities:			
Borrowings under debt facilities	1,193,500	1,180,000	945,000
Repayments under debt facilities	(1,212,250)	(1,027,500)	(820,000)
Debt issuance costs	(346)	(599)	(1,380)
Principal payments under capital lease obligations	(3,246)	(2,446)	(1,150)
Repurchase of shares to satisfy tax obligations	(1,367)	(816)	(843)
Repurchase of common stock	(349,776)	(369,403)	(331,708)
Net proceeds from issuance of common stock	79,643	16,330	41,010
Cash dividends paid to stockholders	(147,087)	(133,828)	(122,272)
Net cash used in financing activities	(440,929)	(338,262)	(291,343)
Net change in cash and cash equivalents	(22,849)	55,232	(9,897)
Cash and cash equivalents at beginning of year	109,148	53,916	63,813
Cash and cash equivalents at end of year	$86,299	$109,148	$53,916
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$18,069	$10,481	$6,124
Income taxes	146,918	219,081	232,258
Supplemental disclosures of non-cash activities:			
Property and equipment acquired through capital lease	$—	$11,395	$10,493

Non-cash accruals for construction in progress	3,001	8,647	12,303

The accompanying notes are an integral part of these Consolidated Financial Statements.

Index

TRACTOR SUPPLY COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Significant Accounting Policies:

Nature of Business

Founded in 1938, Tractor Supply Company (the “Company” or “we” or “our” or “us”) is the largest rural lifestyle retailer in the United States (“U.S.”). The Company is focused on supplying the needs of recreational farmers and ranchers and those who enjoy the rural lifestyle (which we refer to as the “Out Here” lifestyle), as well as tradesmen and small businesses. Stores are located primarily in towns outlying major metropolitan markets and in rural communities. The Company also owns and operates Petsense, LLC (“Petsense”), a small-box pet specialty supply retailer focused on meeting the needs of pet owners, primarily in small and mid-sized communities, and offering a variety of pet products and services. At December 29, 2018, the Company operated a total of 1,940 retail stores in 49 states (1,765 Tractor Supply and Del’s retail stores and 175 Petsense retail stores) and also offered an expanded assortment of products online at TractorSupply.com and Petsense.com.

Basis of Presentation

In the first quarter of fiscal 2018, the Company adopted accounting guidance that allowed for a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the U.S. Tax Cuts and Jobs Act (the “TCJA”) as discussed in Note 15. This guidance was applied retrospectively, which resulted in the reclassification of $0.6 million from accumulated other comprehensive income to retained earnings in the Consolidated Balance Sheets, Statements of Stockholders’ Equity, and Statements of Comprehensive Income as of and for the fiscal year ended December 30, 2017. No other periods presented were affected by the adoption of this accounting guidance.

In the first quarter of fiscal 2017, the Company adopted accounting guidance which affected the presentation in the statement of cash flows of excess tax benefits or deficiencies from the exercise of stock options. The Company elected to apply the amendments using a retrospective transition method for all periods presented and therefore the presentation of previously reported excess tax benefits on the Consolidated Statements of Cash Flows has been changed to conform to the presentation used in the current period. As a result, $11.7 million of excess tax benefits related to share-based awards which were previously classified as cash flows from financing activities have been reclassified as cash flows from operating activities in the Consolidated Statements of Cash Flows for the fiscal year ended December 31, 2016. Additionally, beginning in fiscal 2017, the Consolidated Statements of Stockholders’ Equity are no longer impacted by the excess tax benefits or deficiencies from the exercise of stock options.

Fiscal Year

The Company’s fiscal year includes 52 or 53 weeks and ends on the last Saturday of the calendar year. The fiscal year ended December 29, 2018, consisted of 52 weeks, the fiscal year ended December 30, 2017, consisted of 52 weeks and the fiscal year ended December 31, 2016, consisted of 53 weeks.

Principles of Consolidation

The accompanying Consolidated Financial Statements include the accounts of the Company and its subsidiaries. All intercompany accounts and transactions have been eliminated.

Management Estimates

The preparation of Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States ("U.S. GAAP") inherently requires estimates and assumptions by management of the Company that affect the reported amounts of assets and liabilities, revenues and expenses and related disclosures. Actual results could differ from those estimates.

Significant estimates and assumptions by management primarily impact the following key financial statement areas:

Inventory Valuation

Inventory Impairment Risk
The Company identifies potentially excess and slow-moving inventory by evaluating turn rates, historical and expected future sales trends, age of merchandise, overall inventory levels, current cost of inventory, and other benchmarks. The Company

Index

has established an inventory valuation reserve to recognize the estimated impairment in value (i.e., an inability to realize the full carrying value) based on the Company's aggregate assessment of these valuation indicators under prevailing market conditions and current merchandising strategies. The Company does not believe its merchandise inventories are subject to significant risk of obsolescence in the near term. However, changes in market conditions or consumer purchasing patterns could result in the need for additional reserves.

Shrinkage
The Company performs physical inventories at least once a year for each store that has been open more than 12 months, and the Company has established a reserve for estimating inventory shrinkage between physical inventory counts. The reserve is established by assessing the chain-wide average shrinkage experience rate, applied to the related periods' sales volumes. Such assessments are updated on a regular basis for the most recent individual store experiences. The estimated store inventory shrink rate is based on historical experience. The Company believes historical rates are a reasonably accurate reflection of future trends.

Vendor Funding
The Company receives funding from substantially all of its significant merchandise vendors, in support of its business initiatives, through a variety of programs and arrangements, including guaranteed vendor support funds ("vendor support") and volume-based rebate funds ("volume rebates"). The amounts received are subject to terms of vendor agreements, most of which are "evergreen," reflecting the on-going relationship with our significant merchandise vendors. Certain of the Company's agreements, primarily volume rebates, are renegotiated annually, based on expected annual purchases of the vendor's product. Vendor funding is initially deferred as a reduction of the purchase price of inventory, and then recognized as a reduction of cost of merchandise as the related inventory is sold.

During interim periods, the amount of vendor support and volume rebates are estimated based upon initial commitments and anticipated purchase levels with applicable vendors. The estimated purchase volume (and related vendor funding) is based on the Company's current knowledge of inventory levels, sales trends and expected customer demand, as well as planned new store openings and relocations. Although the Company believes it can reasonably estimate purchase volume and related volume rebates at interim periods, it is possible that actual year-end results could be different from previously estimated amounts.

Freight
The Company incurs various types of transportation and delivery costs in connection with inventory purchases and distribution. Such costs are included as a component of the overall cost of inventories (on an aggregate basis) and recognized as a component of cost of merchandise sold as the related inventory is sold.

Self-Insurance Reserves

The Company self-insures a significant portion of its employee medical insurance, workers' compensation insurance and general liability (including product liability) insurance plans. The Company has stop-loss insurance policies to protect it from individual losses over specified dollar values. For self-insured employee medical claims, we have a stop-loss limit of $300,000 per person per year. Our deductible or self-insured retention, as applicable, for each claim involving workers' compensation insurance and general liability insurance is limited to $500,000 and our Texas Work Injury Policy is limited to $500,000. Further, we maintain a commercially reasonable umbrella/excess policy that covers liabilities in excess of the primary insurance policy limits.

The full extent of certain claims, especially workers' compensation and general liability claims, may not become fully determined for several years. Therefore, the Company estimates potential obligations based upon historical claims experience, industry factors, severity factors, and other actuarial assumptions. Although the Company believes the reserves established for these obligations are reasonably estimated, any significant change in the number of claims or costs associated with claims made under these plans could have a material effect on the Company's financial results. At December 29, 2018, the Company had net insurance reserves of $65.0 million compared to $57.9 million at December 30, 2017.

Impairment of Long-Lived Assets

Long-lived assets are evaluated for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Index

When evaluating long-lived assets for potential impairment, the Company first compares the carrying value of the asset to the asset's estimated undiscounted future cash flows. The evaluation for long-lived assets is performed at the lowest level of identifiable cash flows, which is generally the individual store level. The significant assumptions used to determine estimated undiscounted cash flows include cash inflows and outflows directly resulting from the use of those assets in operations, including margin on net sales, payroll and related items, occupancy costs, insurance allocations and other costs to operate a store. If the estimated future cash flows are less than the carrying value of the asset, the Company calculates an impairment loss. The impairment loss calculation compares the carrying value of the asset to the asset's estimated fair value, which may be based on an estimated future cash flow model. The Company recognizes an impairment loss if the amount of the asset's carrying value exceeds the asset's estimated fair value. If the Company recognizes an impairment loss, the adjusted carrying amount of the asset becomes its new cost basis. For a depreciable long-lived asset, the new cost basis will be depreciated (amortized) over the remaining estimated useful life of that asset.

No significant impairment charges were recognized in fiscal 2018, 2017, or 2016. Impairment charges are included in selling, general and administrative ("SG&A") expenses in the Consolidated Statements of Income.

Impairment of Indefinite-Lived Intangible Assets

Goodwill and other indefinite-lived intangible assets are evaluated for impairment annually, or whenever events or changes in circumstances indicate that the carrying value may not be recoverable.
In accordance with the accounting standards, an entity has the option first to assess qualitative factors to determine whether events and circumstances indicate that it is more likely than not that goodwill or an indefinite-lived intangible asset is impaired. If after such assessment an entity concludes that the asset is not impaired, then the entity is not required to take further action. However, if an entity concludes otherwise, then it is required to determine the fair value of the asset using a quantitative impairment test, and if impaired, the associated assets must be written down to fair value.

The quantitative impairment test for goodwill compares the fair value of a reporting unit with the carrying value of its net assets, including goodwill. If the fair value of the reporting unit is less than the carrying value of the reporting unit, an impairment charge would be recorded to the Company's operations, for the amount, if any, in which the carrying amount exceeds the reporting unit's fair value. We determine fair values for each reporting unit using the market approach, when available and appropriate, or the income approach, or a combination of both. If multiple valuation methodologies are used, the results are weighted appropriately.

The quantitative impairment test for other indefinite-lived intangible assets involves comparing the carrying amount of the asset to the sum of the discounted cash flows expected to be generated by the asset. If the implied fair value of the indefinite-lived intangible asset is less than the carrying value, an impairment charge would be recorded to the Company's operations.

No significant impairment charges were recognized in fiscal 2018, 2017, or 2016. Impairment charges are included in SG&A expenses in the Consolidated Statements of Income.

Revenue Recognition and Sales Returns

The Company recognizes revenue at the time the customer takes possession of merchandise. If the Company receives payment before completion of its customer obligations (as per the Company's special order and layaway programs), the revenue is deferred until the customer takes possession of the merchandise and the sale is complete.

The Company is required to collect certain taxes and fees from customers on behalf of government agencies and remit such collections to the applicable governmental agency on a periodic basis. These taxes and fees are collected from customers at the time of purchase, but are not included in net sales. The Company records a liability upon collection from the customer and relieves the liability when payments are remitted to the applicable governmental agency.

The Company estimates a liability for sales returns based on a rolling average of historical return trends, and the Company believes that its estimate for sales returns is an accurate reflection of future returns associated with past sales. However, as with any estimate, refund activity may vary from estimated amounts. The Company had a liability for sales returns of $11.3 million and $3.8 million as of December 29, 2018 and December 30, 2017, respectively.

The Company recognizes revenue when a gift card or merchandise return card is redeemed by the customer and recognizes income when the likelihood of the gift card or merchandise return card being redeemed by the customer is remote (referred to as

50

"breakage"). The gift cards and merchandise return card breakage rate is based upon historical redemption patterns and income is recognized for unredeemed gift cards and merchandise return cards in proportion to those historical redemption patterns. The Company recognized breakage income of $2.6 million, $2.4 million, and $1.9 million in fiscal 2018, 2017, and 2016, respectively.

Cost of Merchandise Sold

Cost of merchandise sold includes the total cost of products sold; freight and duty expenses associated with moving merchandise inventories from vendors to distribution facilities, from distribution facilities to retail stores, from one distribution facility to another, and directly to our customers; vendor support; damaged, junked or defective product; cash discounts from payments to merchandise vendors; and adjustments for shrinkage (physical inventory losses), lower of cost or net realizable value, slow moving product and excess inventory quantities.

Selling, General and Administrative Expenses

SG&A expenses include payroll and benefit costs for retail, distribution facility, and corporate employees; share-based compensation expenses; occupancy costs of retail, distribution, and corporate facilities; advertising; tender costs, including bank charges and costs associated with credit and debit card interchange fees; outside service fees; and other administrative costs, such as computer maintenance, supplies, travel, and lodging.

Advertising Costs

Advertising costs consist of expenses incurred in connection with newspaper circulars and customer-targeted direct mail, as well as limited television, radio, digital and social media offerings, and other promotions. Costs are expensed when incurred with the exception of television advertising and circular and direct mail promotions, which are expensed upon first showing. Advertising expenses were approximately $83.4 million, $81.3 million, and $84.2 million for fiscal 2018, 2017, and 2016, respectively. Prepaid advertising costs were approximately $1.3 million and $1.1 million as of December 29, 2018, and December 30, 2017, respectively.

Warehousing and Distribution Facility Costs

Costs incurred at the Company's distribution facilities for receiving, warehousing, and preparing product for delivery are expensed as incurred and are included in SG&A expenses in the Consolidated Statements of Income. Because the Company does not include these costs in cost of sales, the Company's gross margin may not be comparable to other retailers that include these costs in the calculation of gross margin. Distribution facility costs including depreciation were approximately $209.7 million, $182.1 million, and $166.8 million for fiscal 2018, 2017, and 2016, respectively.

Pre-Opening Costs

Non-capital expenditures incurred in connection with opening new stores, primarily payroll and rent, are expensed as incurred. Pre-opening costs were approximately $8.5 million, $10.8 million, and $9.9 million for fiscal 2018, 2017, and 2016, respectively.

Share-Based Compensation

The Company has share-based compensation plans covering certain members of management and non-employee directors, which include incentive and non-qualified stock options, restricted stock units, and performance-based restricted share units. In addition, the Company offers an Employee Stock Purchase Plan ("ESPP") to most employees that work at least 20 hours per week.

The Company estimates the fair value of its stock option awards at the date of grant utilizing a Black-Scholes option pricing model. The Black-Scholes option valuation model was developed for use in estimating the fair value of short-term traded options that have no vesting restrictions and are fully transferable. However, key assumptions used in the Black-Scholes model are adjusted to incorporate the unique characteristics of the Company’s stock option awards. Option pricing models and generally accepted valuation techniques require management to make subjective assumptions including expected stock price volatility, expected dividend yield, risk-free interest rate, and expected term. The Company relies on historical volatility trends to estimate future volatility assumptions. The risk-free interest rates used were actual U.S. Treasury Constant Maturity rates for bonds matching the expected term of the option on the date of grant. The expected term of the option on the date of grant was estimated based on the Company’s historical experience for similar options.

In addition to the key assumptions used in the Black-Scholes model, the estimated forfeiture rate at the time of valuation (which is based on historical experience for similar options) is a critical assumption, as it reduces expense ratably over the vesting period.

Index

The Company adjusts this estimate periodically, based on the extent to which actual forfeitures differ, or are expected to differ, from the previous estimate.

The fair value of the Company's restricted stock units and performance-based restricted share units is the closing stock price of the Company's common stock the day preceding the grant date, discounted for the expected dividend yield over the term of the award.

The Company believes its estimates are reasonable in the context of historical experience. Future results will depend on, among other matters, levels of share-based compensation granted in the future, actual forfeiture rates, and the timing of option exercises.

Depreciation and Amortization

Depreciation includes expenses related to all retail, distribution facility, and corporate assets. Amortization includes expenses related to definite-lived intangible assets.

Income Taxes

The Company uses the asset and liability method to account for income taxes whereby deferred tax assets and liabilities are determined based on differences between the financial carrying amounts of assets and liabilities and their tax bases. Deferred tax assets and liabilities are measured using the enacted tax rates and laws that are anticipated to be in effect when temporary differences reverse or are settled. The effect of a tax rate change is recognized in the period in which the law is enacted in the provision for income taxes. The Company records a valuation allowance when it is more likely than not that a deferred tax asset will not be realized.

Tax Contingencies

The Company's income tax returns are periodically audited by U.S. federal and state tax authorities. These audits include questions regarding tax filing positions, including the timing and amount of deductions and the allocation of income among various tax jurisdictions. At any time, multiple tax years are subject to audit by the various tax authorities. In evaluating the exposures associated with the Company's various tax filing positions, the Company records a liability for uncertain tax positions taken or expected to be taken in a tax return. A number of years may elapse before a particular matter, for which the Company has established a reserve, is audited and fully resolved or clarified. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. The Company adjusts its tax contingencies reserve and income tax provision in the period in which actual results of a settlement with tax authorities differs from the established reserve, the statute of limitations expires for the relevant tax authority to examine the tax position or when more information becomes available.

Sales Tax Audit Reserve

A portion of the Company's sales are to tax-exempt customers, predominantly agricultural-based. The Company obtains exemption information as a necessary part of each tax-exempt transaction. Many of the states in which the Company conducts business will perform audits to verify the Company's compliance with applicable sales tax laws. The business activities of the Company's customers and the intended use of the unique products sold by the Company create a challenging and complex tax compliance environment. These circumstances also create some risk that the Company could be challenged as to the accuracy of the Company's sales tax compliance.

The Company reviews past audit experience and assessments with applicable states to continually determine if it has potential exposure for non-compliance. Any estimated liability is based on an initial assessment of compliance risk and historical experience with each state. The Company continually reassesses the exposure based on historical audit results, changes in policies, preliminary and final assessments made by state sales tax auditors, and additional documentation that may be provided to reduce the assessment. The reserve for these tax audits can fluctuate depending on numerous factors, including the complexity of agricultural-based exemptions, the ambiguity in state tax regulations, the number of ongoing audits, and the length of time required to settle with the state taxing authorities.

Index

Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of shares outstanding during the period. Diluted net income per share is calculated by dividing net income by the weighted average diluted shares outstanding. Dilutive shares are computed using the treasury stock method for stock options, restricted stock units, and performance-based restricted share units. Performance-based restricted share units are included in diluted shares only if the relative performance conditions have been considered satisfied as of the end of the reporting period.

Cash and Cash Equivalents

Temporary cash investments, with a maturity of three months or less when purchased, are considered to be cash equivalents. The majority of payments due from banks for customer credit cards are classified as cash and cash equivalents, as they generally settle within 24-48 hours.

Sales generated through the Company's private label credit cards are not reflected as accounts receivable. Under an agreement with Citi Cards, a division of Citigroup, consumer and business credit is extended directly to customers by Citigroup. All credit program and related services are performed and controlled directly by Citigroup. Payments due from Citigroup are classified as cash and cash equivalents as they generally settle within 24-48 hours.

Fair Value of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants on the measurement date. The Company uses a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Company's financial instruments consist of cash and cash equivalents, short-term receivables, trade payables, debt instruments, and interest rate swaps. Due to their short-term nature, the carrying values of cash and cash equivalents, short-term receivables, and trade payables approximate current fair value at each balance sheet date. The Company had $408.8 million and $427.5 million in borrowings under our debt facilities (as discussed in Note 5) as of December 29, 2018 and December 30, 2017, respectively. Based on current market interest rates (Level 2 inputs), the carrying value of our borrowings under our debt facilities approximates fair value for each period reported. The fair value of the Company's interest rate swaps is determined based on the present value of expected future cash flows using forward rate curves (a Level 2 input). As described in further detail in Note 6, the fair value of the interest rate swaps, excluding accrued interest, was a $5.8 million and $5.2 million asset as of December 29, 2018 and December 30, 2017, respectively.

Derivative Financial Instruments

The Company accounts for derivative financial instruments in accordance with applicable accounting standards for such instruments and hedging activities, which require that all derivatives are recorded on the balance sheet at fair value. The accounting for changes in the fair value of derivatives depends on the intended use of the derivative, whether the Company has elected to designate a derivative in a hedging relationship and apply hedge accounting and whether the hedging relationship has satisfied the criteria necessary to apply hedge accounting.

Derivatives designated and qualifying as a hedge of the exposure to changes in the fair value of an asset, liability, or firm commitment attributable to a particular risk are considered fair value hedges. Derivatives designated and qualifying as a hedge of the exposure to variability in expected future cash flows, or other types of forecasted transactions, are considered cash flow hedges. Hedge accounting generally provides for the matching of the timing of gain or loss recognition on the hedging instrument with the recognition of the changes in the fair value of the hedged asset or liability that are attributable to the hedged risk in a fair value hedge or the earnings effect of the hedged forecasted transactions in a cash flow hedge. The Company may enter into derivative contracts that are intended to economically hedge a certain portion of its risk, even though hedge accounting does not apply or the Company elects not to apply the hedge accounting standards.

Index

Inventories

Inventories are stated at the lower of cost, as determined by the average cost method, or net realizable value. Inventory cost consists of the direct cost of merchandise including freight. Inventories are net of shrinkage, obsolescence, other valuations, and vendor allowances.

Property and Equipment

Property and equipment are carried at cost. Depreciation is recorded using the straight-line method over the estimated useful lives of the assets. Improvements to leased premises are amortized using the straight-line method over the initial term of the lease or the useful life of the improvement, whichever is less. The following estimated useful lives are generally applied:

	Life
Buildings	30 – 35 years
Leasehold and building improvements	1 – 35 years
Furniture, fixtures and equipment	5 – 10 years
Computer software and hardware	2 – 7 years

The Company entered into agreements with various governmental entities in the states of Kentucky, Georgia, and Tennessee to implement tax abatement plans related to its distribution center in Franklin, Kentucky (Simpson County), its distribution center in Macon, Georgia (Bibb County), and its Store Support Center in Brentwood, Tennessee (Williamson County). The tax abatement plans provide for reduction of real property taxes for specified time frames by legally transferring title to its real property in exchange for industrial revenue bonds. This property was then leased back to the Company. No cash was exchanged.

The lease payments are equal to the amount of the payments on the bonds. The tax abatement period extends through the term of the lease, which coincides with the maturity date of the bonds. At any time, the Company has the option to purchase the real property by paying off the bonds, plus $1. The terms and amounts authorized and drawn under each industrial revenue bond agreement are outlined as follows, as of December 29, 2018:

	Bond Term	Bond Authorized Amount (in millions)	Amount Drawn (in millions)
Franklin, Kentucky Distribution Center	30 years	$54.0	$51.8
Macon, Georgia Distribution Center	15 years	$58.0	$49.9
Brentwood, Tennessee Store Support Center	10 years	$78.0	$75.3

Due to the form of these transactions, the Company has not recorded the bonds or the lease obligation associated with the sale lease-back transaction. The original cost of the Company's property and equipment is recorded on the balance sheet and is being depreciated over its estimated useful life.

Capitalized Software Costs

The Company capitalizes certain costs related to the acquisition and development of software and amortizes these costs using the straight-line method over the estimated useful life of the software, which is two to seven years. Computer software consists of software developed for internal-use and third-party software purchased for internal-use. A subsequent addition, modification or upgrade to internal-use software is capitalized to the extent that it enhances the software's functionality or extends its useful life. These costs are included in computer software and hardware in the accompanying Consolidated Balance Sheets. Certain software costs not meeting the criteria for capitalization are expensed as incurred.

Store Closing Costs

The Company regularly evaluates the performance of its stores and periodically closes those stores that are underperforming. The Company records a liability for costs associated with an exit or disposal activity when the liability is incurred, usually in the period the store closes. Store closing costs were not significant to the results of operations for any of the fiscal years presented.

Index

Leases

Assets under capital leases are amortized in accordance with the Company's normal depreciation policy for owned assets or over the lease term, if shorter, and the related charge to operations is included in depreciation expense in the Consolidated Statements of Income.

Certain operating leases include rent increases during the lease term. For these leases, the Company recognizes the related rental expense on a straight-line basis over the term of the lease (which includes the pre-opening period of construction, renovation, fixture and merchandise placement) and records the difference between the expense charged to operations and amounts paid as a deferred rent liability.

The Company occasionally receives reimbursements from landlords to be used towards improving the related store to be leased. Leasehold improvements are recorded at their gross costs, including items reimbursed by landlords. Related reimbursements are deferred and amortized on a straight-line basis as a reduction of rent expense over the applicable lease term.

Note 2 – Share-Based Compensation:

Share-based compensation includes stock options, restricted stock units, performance-based restricted share units, and certain transactions under the Company's ESPP. Share-based compensation expense is recognized based on the grant date fair value of all stock options, restricted stock units, and performance-based restricted share units plus a discount on shares purchased by employees as a part of the ESPP. The discount under the ESPP represents the difference between the purchase date market value and the employee's purchase price.

There were no significant modifications to the Company's share-based compensation plans during fiscal 2017 or 2016. In fiscal 2018, there were no significant modifications to the Company's share-based compensation plans prior to May 10, 2018, when the Company's shareholders approved the 2018 Omnibus Incentive Plan (the "2018 Plan") replacing the 2009 Stock Incentive Plan. Following the adoption of the 2018 Plan, no further grants may be made under the 2009 Stock Incentive Plan. Subject to adjustment as provided by the terms of the 2018 Plan, the maximum number of shares of common stock with respect to which awards may be granted under the 2018 Plan is 12,562,318. The maximum number of shares with respect to which awards may be granted under the 2018 Plan shall be increased by the number of shares with respect to which options or other awards were granted under the 2009 Stock Incentive Plan or the 2006 Stock Incentive Plan but which terminate, expire unexercised, or are settled for cash, forfeited, or canceled without the delivery of shares after the effective date of the 2018 Plan.

Under our 2018 Plan, awards may be granted to officers, non-employee directors, other employees, and independent contractors. The per share exercise price of options granted shall not be less than the fair market value of the stock on the date of grant and such awards will expire no later than ten years from the date of grant. Vesting of awards commences at various anniversary dates following the dates of each grant and certain awards will vest only upon established performance conditions being met. At December 29, 2018, the Company had approximately 12.7 million shares available for future equity awards under the Company's 2018 Plan.

Share-based compensation expense, including changes in expense for modifications, if any, of awards, was $28.9 million, $29.2 million, and $23.6 million for fiscal 2018, 2017, and 2016, respectively.

Stock Options

Under the Company's share-based compensation plans, options may be granted to current or prospective officers or employees, non-employee directors, and independent contractors. The per share exercise price of options granted shall not be less than the fair market value of the stock on the date of grant and such options will expire no later than ten years from the date of grant. Vesting of options commences at various anniversary dates following the dates of grant.

The fair value is separately estimated for each option grant. The fair value of each option is recognized as compensation expense ratably over the vesting period. The Company has estimated the fair value of all stock option awards as of the date of the grant by applying a Black-Scholes pricing valuation model. The application of this valuation model involves assumptions that are judgmental and highly sensitive in the determination of compensation expense. The ranges of key assumptions used in determining the fair value of options granted during fiscal 2018, 2017, and 2016, as well as a summary of the methodology applied to develop each assumption, are as follows:

Index

	Fiscal Year 2018	2017	2016
Expected price volatility	26.4 - 27.0%	25.1 - 26.0%	25.5 - 27.9%
Risk-free interest rate	2.5 - 3.0%	1.7 - 1.9%	0.9 - 1.3%
Weighted average expected term (in years)	4.5	4.4	4.4
Forfeiture rate	7.3 %	7.2 %	7.1 %
Dividend yield	1.6 %	1.3 %	0.9 %

Expected Price Volatility — This is a measure of the amount by which a price has fluctuated or is expected to fluctuate. The Company applies a historical volatility rate. To calculate historical changes in market value, the Company uses daily market value changes from the date of grant over a past period generally representative of the expected life of the options to determine volatility. The Company believes the use of historical price volatility provides an appropriate indicator of future volatility. An increase in the expected volatility will increase compensation expense.

Risk-Free Interest Rate — This is the U.S. Treasury Constant Maturity rate over a term equal to the expected term of the option. An increase in the risk-free interest rate will increase compensation expense.

Weighted Average Expected Term — This is the period of time over which the options granted are expected to remain outstanding and is based on historical experience. Options granted generally have a maximum term of ten years. An increase in the expected term will increase compensation expense.

Forfeiture Rate — This is the estimated percentage of options granted that are expected to be forfeited or canceled before becoming fully vested. This estimate is based on historical experience. An increase in the forfeiture rate will decrease compensation expense.

Dividend Yield — This is the estimated dividend yield for the weighted average expected term of the option granted. An increase in the dividend yield will decrease compensation expense.

The Company issues shares for options when exercised. A summary of stock option activity is as follows:

Stock Option Activity	Options	Weighted Average Exercise Price	Weighted Average Fair Value	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at December 30, 2017	4,998,526	$ 68.46		6.9	$ 50,145
Granted	693,634	67.81	$ 15.02		
Exercised	(1,380,136)	54.55			
Canceled	(258,638)	77.83			
Outstanding at December 29, 2018	4,053,386	$ 72.49		7.0	$ 46,472
Exercisable at December 29, 2018	2,173,274	$ 72.32		5.8	$ 25,747

The aggregate intrinsic values in the table above represent the total difference between the Company's closing stock price at each year-end and the option exercise price, multiplied by the number of in-the-money options at each year-end. As of December 29, 2018, total unrecognized compensation expense related to non-vested stock options was approximately $12.3 million with a weighted average expense recognition period of 1.6 years.

There were no material modifications to options in fiscal 2018, 2017, or 2016.

Other information relative to options activity during fiscal 2018, 2017, and 2016 is as follows (in thousands):

	Fiscal Year		
	2018	2017	2016
Total fair value of stock options vested	$18,247	$15,996	$15,184
Total intrinsic value of stock options exercised	$43,476	$9,237	$39,696

Index

Restricted Stock Units

The Company issues shares for restricted stock units once vesting occurs and related restrictions lapse. The fair value of the restricted stock units is the closing price of the Company's common stock the day preceding the grant date, discounted for the expected dividend yield over the term of the award. The units vest over a one to three-year term; some plan participants have elected to defer receipt of shares of common stock upon vesting of restricted stock units, and as a result, those shares are not issued until a later date. A summary of restricted stock unit activity is presented below:

Restricted Stock Unit Activity	Restricted Stock Units	Weighted Average Grant Date Fair Value
Restricted at December 30, 2017	223,230	$ 67.92
Granted	309,978	64.00
Exercised	(70,845)	75.16
Forfeited	(24,293)	65.84
Restricted at December 29, 2018	438,070	$ 64.09

Other information relative to restricted stock unit activity during fiscal 2018, 2017, and 2016 is as follows (in thousands):

	Fiscal Year		
	2018	2017	2016
Total grant date fair value of restricted stock units vested and issued	$5,325	$3,301	$3,072
Total intrinsic value of restricted stock units vested and issued	$5,364	$3,465	$5,104

For the majority of restricted stock units granted, the number of shares issued on the date the restricted stock units vest is net of shares withheld by the Company to satisfy the minimum statutory tax withholding requirements, which the Company pays on behalf of its employees. The Company issued 53,714, 39,314, and 48,267 shares as a result of vested restricted stock units during fiscal 2018, 2017, and 2016, respectively. Although shares withheld are not issued, they are treated similar to common stock repurchases as they reduce the number of shares that would have been issued upon vesting. The amounts are net of 17,131, 11,755, and 10,236 shares withheld to satisfy $1.4 million of employees' tax obligations during fiscal 2018 and $0.8 million during both fiscal 2017 and 2016.

There were no material modifications to restricted stock units in fiscal 2018, 2017, or 2016.

As of December 29, 2018, total unrecognized compensation expense related to non-vested restricted stock units was approximately $13.5 million with a weighted average expense recognition period of 2.0 years.

Performance-Based Restricted Share Units

We issue performance-based restricted share units to senior executives that represent shares potentially issuable in the future, subject to the achievement of specified performance goals. The performance metrics for the units are growth in net sales and growth in earnings per diluted share over a one-year performance period. Issuance is based upon the level of achievement of the relative performance targets. If the performance targets are achieved, the units will vest on a pro-rata basis over a three-year period. The fair value of the performance-based restricted share units is the closing price of the Company's common stock the day preceding the grant date, discounted for the expected dividend yield over the term of the awards. A summary of performance-based restricted share unit activity is presented below:

Performance-Based Restricted Share Unit Activity	Performance-Based Restricted Share	Weighted Average

	Units	Grant Date Fair Value
Restricted at December 30, 2017	—	$ —
Granted [(a)]	41,310	63.90
Exercised	—	—
Forfeited	—	—
Restricted at December 29, 2018	41,310	$ 63.90

[(a)] Assumes 100% target level achievement of the relative performance targets. The actual number of shares that will be issued, which may be higher or lower than the target, will be determined by the level of achievement of the relative performance targets.

Index

There were no vested or issued performance-based restricted share units as of fiscal 2018, 2017, or 2016, and as such, there was no associated fair value or intrinsic value for these awards.

There were no material modifications to performance-based restricted share units in fiscal 2018, 2017, or 2016.

As of December 29, 2018, total unrecognized compensation expense related to non-vested performance-based restricted share units was approximately $1.3 million with a weighted average expense recognition period of 2.2 years.

Employee Stock Purchase Plan

The ESPP provides Company employees the opportunity to purchase, through payroll deductions, shares of common stock at a 15% discount. Pursuant to the terms of the ESPP, the Company issued 77,458, 83,155, and 69,562 shares of common stock during fiscal 2018, 2017, and 2016, respectively. The total cost related to the ESPP, including the compensation expense calculations, was approximately $1.1 million, $1.0 million, and $1.1 million in fiscal 2018, 2017, and 2016, respectively. There is a maximum of 16.0 million shares of common stock that are reserved under the ESPP. At December 29, 2018, there were approximately 11.9 million remaining shares of common stock reserved for future issuance under the ESPP.

Note 3 – Acquisition of Petsense:

On September 29, 2016, the Company completed the acquisition of Petsense. Headquartered in Scottsdale, Arizona, Petsense is a small-box pet specialty supply retailer focused on meeting the needs of pet owners, primarily in small and mid-size communities, and offering a variety of pet products and services. Pursuant to the agreement governing the transaction, the Company acquired all the outstanding equity interests in Petsense for an all-cash purchase price which was financed with cash on-hand and revolver borrowings under the 2016 Senior Credit Facility (as defined in Note 5).

The total consideration transferred in connection with the Petsense acquisition has been allocated to the assets acquired and liabilities assumed based upon their respective fair values. The fair value of the assets acquired and liabilities assumed is estimated based on either one or a combination of the following methodologies: the income approach, the cost approach or the market approach as determined based on the nature of the asset or liability and the level of inputs available. With respect to assets and liabilities, the determination of fair value requires management to make subjective judgments as to projections of future operating performance, the appropriate discount rate to apply, long-term growth rates, etc. (i.e. unobservable inputs classified as Level 3 inputs under the fair value hierarchy), which affect the amounts recorded in the purchase price allocation. The excess of the consideration transferred over the fair value of the identifiable assets, net of liabilities, is recorded as goodwill, which is indicative of the expected continued growth and development of the pet specialty retail business acquired.

The table below summarizes the consideration transferred and allocation of the purchase price for the Petsense acquisition (in thousands):

Consideration transferred	$144,476
Assets acquired:	
Current assets	$21,875
Property and equipment	25,519
Other intangible assets - tradename	31,300
Other assets	428
Liabilities assumed:	
Current liabilities	(12,091)
Long-term liabilities	(5,489)

Total identifiable net assets acquired	61,542
Excess of consideration transferred over identifiable net assets acquired (goodwill)	$82,934

In September 2017, the Company finalized the working capital settlement pursuant to the agreement governing the transaction. As a result, the values of the consideration transferred, assets acquired and liabilities assumed as reflected in the table above are considered final. The working capital settlement reduced both the consideration transferred and goodwill by $1.2 million from the preliminary values.

The resulting goodwill of $82.9 million and tradename of $31.3 million are amortized for income tax purposes.

The results of operations of Petsense have been included in the Consolidated Financial Statements since the date of acquisition.

Index

Note 4 – Goodwill and Other Intangible Assets:

Goodwill

The Company had approximately $93.2 million of goodwill at December 29, 2018 and December 30, 2017. The changes in the carrying amount of goodwill for the years ended December 29, 2018 and December 30, 2017, are as follows (in thousands):

	Fiscal Year	
	2018	2017
Balance, beginning of year	$93,192	$94,417
Working capital settlement	—	(1,225)
Balance, end of year	$93,192	$93,192

Goodwill is allocated to each identified reporting unit, which is defined as an operating segment or one level below the operating segment.

Goodwill is not amortized, but is evaluated for impairment annually and whenever events or changes in circumstances indicate the carrying value of goodwill may not be recoverable. The Company completes its impairment evaluation by performing valuation analyses and considering other publicly available market information, as appropriate.

The test used to identify the potential for goodwill impairment compares the fair value of a reporting unit with its carrying value. An impairment charge would be recorded to the Company's operations for the amount, if any, in which the carrying value exceeds the fair value.

In the fourth quarter of fiscal 2018, the Company completed its annual impairment testing of goodwill and no impairment was identified. The Company determined that the fair value of each reporting unit (including goodwill) was in excess of the carrying value of the respective reporting unit. In reaching this conclusion, the fair value of each reporting unit was determined based on either a market or an income approach. Under the market approach, the fair value is based on observed market data.

Other Intangible Assets

The Company had approximately $31.3 million of intangible assets other than goodwill at December 29, 2018 and December 30, 2017. The intangible asset balance represents the estimated fair value of the Petsense tradename, which is not subject to amortization as it has an indefinite useful life on the basis that it is expected to contribute cash flows beyond the foreseeable horizon.

With respect to intangible assets, we evaluate for impairment annually and whenever events or changes in circumstances indicate that the carrying value may not be recoverable. We recognize an impairment loss only if the carrying amount is not recoverable through its discounted cash flows and measure the impairment loss based on the difference between the carrying value and fair value. In the fourth quarter of fiscal 2018, the Company completed its annual impairment testing of intangible assets and no impairment was identified.

Note 5 – Debt:

The following table summarizes the Company’s outstanding debt as of the dates indicated (in millions):

	December 29, 2018	December 30, 2017
Senior Notes	$ 150.0	$ 150.0
Senior Credit Facility:		
February 2016 Term Loan	165.0	180.0
June 2017 Term Loan	93.8	97.5
Revolving credit loans	—	—
Total outstanding borrowings	408.8	427.5
Less: unamortized debt issuance costs	(1.4)	(1.4)
Total debt	407.4	426.1
Less: current portion of long-term debt	(26.3)	(25.0)
Long-term debt	$ 381.1	$ 401.1
Outstanding letters of credit	$ 33.5	$ 39.6

Senior Notes

On August 14, 2017, the Company entered into a note purchase and private shelf agreement (the “Note Purchase Agreement”), pursuant to which the Company agreed to sell $150 million aggregate principal amount of senior unsecured notes due August 14, 2029 (the “2029 Notes”) in a private placement. The 2029 Notes bear interest at 3.70% per annum with interest payable semi-annually in arrears on each annual and semi-annual anniversary of the issuance date. The obligations under the Note Purchase Agreement are unsecured, but guaranteed by each of the Company’s material subsidiaries.

The Company may from time to time issue and sell additional senior unsecured notes (the “Shelf Notes”) pursuant to the Note Purchase Agreement, in an aggregate principal amount of up to $150 million. The Shelf Notes will have a maturity date of no more than 12 years after the date of original issuance and may be issued through August 14, 2020, unless earlier terminated in accordance with the terms of the Note Purchase Agreement.

Pursuant to the Note Purchase Agreement, the 2029 Notes and any Shelf Notes (collectively, the "Notes") are redeemable by the Company, in whole at any time or in part from time to time, at 100% of the principal amount of the Notes being redeemed, together with accrued and unpaid interest thereon and a make whole amount calculated by discounting all remaining scheduled payments on the Notes by the yield on the U.S. Treasury security with a maturity equal to the remaining average life of the Notes plus 0.50%.

Senior Credit Facility

On February 19, 2016, the Company entered into a senior credit facility (the “2016 Senior Credit Facility”) consisting of a $200 million term loan (the “February 2016 Term Loan”) and a $500 million revolving credit facility (the “Revolver”) with a sublimit of $50 million for swingline loans. This agreement is unsecured. On February 16, 2018, the maturity date was extended from February 19, 2021 to February 19, 2022.

On June 15, 2017, pursuant to an accordion feature available under the 2016 Senior Credit Facility, the Company entered into an incremental term loan agreement (the “June 2017 Term Loan”) which increased the term loan capacity under the 2016 Senior Credit Facility by $100 million. This agreement is unsecured and matures on June 15, 2022.

The February 2016 Term Loan of $200 million requires quarterly payments totaling $10 million per year in years one and two and $20 million per year in years three through the maturity date, with the remaining balance due in full on the maturity date of February 19, 2022. The June 2017 Term Loan of $100 million requires quarterly payments totaling $5 million per year in years one and two and $10 million per year in years three through the maturity date, with the remaining balance due in full on the maturity date of June 15, 2022. The 2016 Senior Credit Facility also contains a $500 million revolving credit facility (with a sublimit of $50 million for swingline loans).

Index

Borrowings under the February 2016 Term Loan and Revolver bear interest at either the bank's base rate (5.500% at December 29, 2018) or the London Inter-Bank Offer Rate ("LIBOR") (2.503% at December 29, 2018) plus an additional amount ranging from 0.500% to 1.125% per annum (0.750% at December 29, 2018), adjusted quarterly based on our leverage ratio. The Company is also required to pay, quarterly in arrears, a commitment fee for unused capacity ranging from 0.075% to 0.200% per annum (0.125% at December 29, 2018), adjusted quarterly based on the Company's leverage ratio. Borrowings under the June 2017 Term Loan bear interest at either the bank's base rate (5.500% at December 29, 2018) or LIBOR (2.503% at December 29, 2018) plus an additional 1.000% per annum. As further described in Note 6, the Company has entered into interest rate swap agreements in order to hedge our exposure to variable rate interest payments associated with each of the term loans under the 2016 Senior Credit Facility.

Proceeds from the 2016 Senior Credit Facility may be used for working capital, capital expenditures, dividends, share repurchases, and other matters. There are no compensating balance requirements associated with the 2016 Senior Credit Facility.

Covenants and Default Provisions of the Debt Agreements

The 2016 Senior Credit Facility and the Note Purchase Agreement (collectively, the "Debt Agreements") require quarterly compliance with respect to two material covenants: a fixed charge coverage ratio and a leverage ratio. Both ratios are calculated on a trailing twelve-month basis at the end of each fiscal quarter. The fixed charge coverage ratio compares earnings before interest, taxes, depreciation, amortization, share-based compensation and rent expense ("consolidated EBITDAR") to the sum of interest paid and rental expense (excluding any straight-line rent adjustments). The fixed charge coverage ratio shall be greater than or equal to 2.00 to 1.0 as of the last day of each fiscal quarter. The leverage ratio compares rental expense (excluding any straight-line rent adjustments) multiplied by a factor of six plus total debt to consolidated EBITDAR. The leverage ratio shall be less than or equal to 4.00 to 1.0 as of the last day of each fiscal quarter. The Debt Agreements also contain certain other restrictions regarding additional indebtedness, capital expenditures, business operations, guarantees, investments, mergers, consolidations and sales of assets, transactions with subsidiaries or affiliates, and liens. As of December 29, 2018, the Company was in compliance with all debt covenants.

The Debt Agreements contain customary events of default, including payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to other material indebtedness, certain events of bankruptcy and insolvency, material judgments, certain ERISA events and invalidity of loan documents. Upon certain changes of control, payment under the Debt Agreements could become due and payable. In addition, under the Note Purchase Agreement, upon an event of default or change of control, the make whole payment described above may become due and payable.

The Note Purchase Agreement also requires that, in the event the Company amends its 2016 Senior Credit Facility, or any subsequent credit facility of $100 million or greater, such that it contains covenant or default provisions that are not provided in the Note Purchase Agreement or that are similar to those contained in the Note Purchase Agreement but which contain percentages, amounts, formulas or grace periods that are more restrictive than those set forth in the Note Purchase Agreement or are otherwise more beneficial to the lenders thereunder, the Note Purchase Agreement shall be automatically amended to include such additional or amended covenants and/or default provisions.

Note 6 – Interest Rate Swaps:

The Company entered into an interest rate swap agreement which became effective on March 31, 2016, with a maturity date of February 19, 2021. The notional amount of this swap agreement began at $197.5 million (the principal amount of the February 2016 Term Loan borrowings as of March 31, 2016) and will amortize at the same time and in the same amount as the February 2016 Term Loan borrowings as described in Note 5, up to the maturity date of the interest rate swap agreement on February 19, 2021. As of December 29, 2018, the notional amount of the interest rate swap was $165.0 million.

The Company entered into a second interest rate swap agreement which became effective on June 30, 2017, with a maturity date of June 15, 2022. The notional amount of this swap agreement began at $100 million (the principal amount of the June 2017 Term Loan borrowings as of June 30, 2017) and will amortize at the same time and in the same amount as the June 2017 Term Loan borrowings as described in Note 5. As of December 29, 2018, the notional amount of the interest rate swap was $93.8 million.

The Company’s interest rate swap agreements are executed for risk management and are not held for trading purposes. The objective of the interest rate swap agreements is to mitigate interest rate risk associated with future changes in interest rates. To accomplish this objective, the interest rate swap agreements are intended to hedge the variable cash flows associated with the variable rate term loan borrowings under the 2016 Senior Credit Facility. Both interest rate swap agreements entitle the Company to receive, at specified intervals, a variable rate of interest based on LIBOR in exchange for the payment of a fixed rate of interest throughout the life of the agreement, without exchange of the underlying notional amount.

The Company has designated its interest rate swap agreements as cash flow hedges and accounts for the underlying activity in accordance with hedge accounting. The interest rate swaps are presented within the Consolidated Balance Sheets at fair value. In accordance with hedge accounting, the effective portion of gains and losses on interest rate swaps that are designated and qualify as cash flow hedges are recorded as a component of Other Comprehensive Income ("OCI") and reclassified into earnings in the period during which the hedged transactions affect earnings. The ineffective portion of gains and losses on interest rate swaps, if any, are recognized in current earnings.

The assets measured at fair value related to the Company's interest rate swaps, excluding accrued interest, were as follows (in thousands):

	Balance Sheet Location	December 29, 2018	December 30, 2017
Interest rate swaps (short-term portion)	Other current assets	$ 2,601	$ 900
Interest rate swaps (long-term portion)	Other assets	3,222	4,252
Total net assets		$ 5,823	$ 5,152

The offset to the interest rate swap asset or liability is recorded as a component of equity, net of deferred taxes, in Accumulated Other Comprehensive Income ("AOCI"), and will be reclassified into earnings over the term of the underlying debt as interest payments are made.

The following table summarizes the changes in AOCI, net of tax, related to the Company's interest rate swaps (in thousands):

	Fiscal Year	
	2018	2017
Beginning fiscal year AOCI balance	$3,358	$1,392
Current fiscal year gain recognized in OCI	456	1,371
Reclassification of stranded tax effects to retained earnings [(a)]	—	595
Other comprehensive gain, net of tax	456	1,966
Ending fiscal year AOCI balance	$3,814	$3,358

[(a)] AOCI for the fiscal year ended December 30, 2017 has been adjusted from previously reported amounts as a result of the adoption of ASU 2018-02 as discussed in Notes 1 and 15 to the Consolidated Financial Statements.

Cash flows related to the interest rate swaps are included in operating activities on the Consolidated Statements of Cash Flows.

The following table summarizes the impact of pre-tax gains and losses derived from the Company's interest rate swaps (in thousands):

		Fiscal Year		
	Financial Statement Location	2018	2017	2016
Effective portion of gains recognized in OCI during the period	Other comprehensive income	$612	$2,240	$2,283
Ineffective portion of gains recognized in earnings during the period	Interest expense, net	59	95	534

The following table summarizes the impact of taxes affecting AOCI as a result of the Company's interest rate swaps (in thousands):

Fiscal Year

	2018	2017
Income tax expense of interest rate swaps on AOCI	$156	$869

Index

Credit-risk-related contingent features

In accordance with the underlying interest rate swap agreements, the Company could be declared in default on its interest rate swap obligations if repayment of the underlying indebtedness (i.e., the Company's term loans) is accelerated by the lender due to the Company's default on such indebtedness.

If the Company had breached any of the provisions in the underlying agreements at December 29, 2018, it could have been required to post full collateral or settle its obligations under the Company's interest rate swap agreements. However, as of December 29, 2018, the Company had not breached any of these provisions or posted any collateral related to the underlying interest rate swap agreements. Further, as of December 29, 2018, the net balance of each of the Company's interest rate swaps were in a net asset position and therefore the Company would have no obligation upon default.

Note 7 – Leases:

The Company leases the majority of its retail store locations, two distribution sites, its Merchandise Innovation Center, transportation equipment, and other equipment under various non-cancellable operating leases. The leases have varying terms and expire at various dates through 2037. Store leases typically have initial terms of between 10 and 15 years, with two to four optional renewal periods of five years each. Some leases require the payment of contingent rent that is based upon store sales above agreed-upon sales levels for the year. The sales levels vary for each store and are established in the lease agreements. Generally, most of the leases also require that the Company pays associated taxes, insurance, and maintenance costs.
Total rent expense was approximately $342.2 million, $319.5 million, and $293.0 million for fiscal 2018, 2017, and 2016, respectively. Total contingent rent expense was insignificant for fiscal 2018, 2017, and 2016.

Future minimum payments, by year and in the aggregate, under leases with initial or remaining terms of one year or more consist of the following (in thousands):

	Capital Leases	Operating Leases
2019	$5,215	$344,836
2020	5,234	328,589
2021	5,294	306,572
2022	4,172	284,327
2023	2,980	260,518
Thereafter	20,169	1,175,972
Total minimum lease payments	43,064	$2,700,814
Amount representing interest	(10,148)	
Present value of minimum lease payments	32,916	
Less: current portion	(3,646)	
Long-term capital lease obligations	$29,270	

Assets under capital leases were as follows (in thousands):

	December 29, 2018	December 30, 2017
Building and improvements, gross	$29,324	$29,324
Computer software and hardware	11,388	11,388
Less: accumulated depreciation and amortization	(10,690)	(6,462)
Assets under capital lease, net	$30,022	$34,250

Note 8 – Capital Stock and Dividends:

Capital Stock

The authorized capital stock of the Company consists of common stock and preferred stock. The Company is authorized to issue 400 million shares of common stock. The Company is also authorized to issue 40 thousand shares of preferred stock, with such designations, rights and preferences as may be determined from time to time by the Company's Board of Directors.

Index

Dividends

During fiscal 2018 and 2017, the Company's Board of Directors declared the following cash dividends:

Date Declared	Dividend Amount Per Share	Stockholders of Record Date	Date Paid
November 7, 2018	$0.31	November 26, 2018	December 11, 2018
August 8, 2018	$0.31	August 27, 2018	September 11, 2018
May 9, 2018	$0.31	May 29, 2018	June 12, 2018
February 7, 2018	$0.27	February 26, 2018	March 13, 2018
November 6, 2017	$0.27	November 20, 2017	December 5, 2017
August 7, 2017	$0.27	August 21, 2017	September 6, 2017
May 8, 2017	$0.27	May 22, 2017	June 6, 2017
February 8, 2017	$0.24	February 27, 2017	March 14, 2017

It is the present intention of the Company's Board of Directors to continue to pay a quarterly cash dividend; however, the declaration and payment of future dividends will be determined by the Company's Board of Directors in its sole discretion and will depend upon the earnings, financial condition, and capital needs of the Company, as well as other factors which the Company's Board of Directors deem relevant.

On February 6, 2019, the Company's Board of Directors declared a quarterly cash dividend of $0.31 per share of the Company's common stock. The dividend will be paid on March 12, 2019, to stockholders of record as of the close of business on February 25, 2019.

Note 9 – Treasury Stock:

The Company's Board of Directors has authorized common stock repurchases under a share repurchase program of up to $3 billion, exclusive of any fees, commissions or other expenses related to such repurchases through December 31, 2020. The repurchases may be made from time to time on the open market or in privately negotiated transactions. The timing and amount of any shares repurchased under the program will depend on a variety of factors, including price, corporate and regulatory requirements, capital availability and other market conditions. Repurchased shares are accounted for at cost and will be held in treasury for future issuance. The program may be limited or terminated at any time without prior notice.

The Company repurchased approximately 5.0 million, 5.9 million, and 4.4 million shares of common stock under the share repurchase program at a total cost of $349.8 million, $369.4 million, and $331.7 million in fiscal 2018, 2017, and 2016, respectively. As of December 29, 2018, the Company had remaining authorization under the share repurchase program of $520.0 million, exclusive of any fees, commissions or other expenses.

Note 10 – Net Income Per Share:

Net income per share is calculated as follows (in thousands, except per share amounts):

	Fiscal Year 2018		
	Net Income	Shares	Per Share Amount
Basic net income per share	$532,357	122,651	$4.34
Dilutive stock options and other share-based awards outstanding	—	820	(0.03)

Diluted net income per share	$532,357	123,471	$ 4.31

64

Index

	Fiscal Year 2017		
	Net Income	Shares	Per Share Amount
Basic net income per share	$422,599	127,588	$ 3.31
Dilutive stock options and other share-based awards outstanding	—	616	(0.01)
Diluted net income per share	$422,599	128,204	$ 3.30

	Fiscal Year 2016		
	Net Income	Shares	Per Share Amount
Basic net income per share	$437,120	132,905	$ 3.29
Dilutive stock options and other share-based awards outstanding	—	908	(0.02)
Diluted net income per share	$437,120	133,813	$ 3.27

Anti-dilutive stock awards excluded from the above calculations totaled approximately 3.1 million, 3.9 million, and 1.9 million shares in fiscal 2018, 2017, and 2016, respectively.

Note 11 – Income Taxes:

The provision for income taxes consists of the following (in thousands):

	Fiscal Year		
	2018	2017	2016
Current tax expense:			
Federal	$123,388	$207,986	$221,207
State	15,597	14,516	20,858
Total current	138,985	222,502	242,065
Deferred tax expense (benefit):			
Federal	9,650	22,469	12,256
State	2,393	4,953	(3,171)
Total deferred	12,043	27,422	9,085
Total provision	$151,028	$249,924	$251,150

Index

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	December 29, 2018	December 30, 2017
Tax assets:		
Inventory valuation	$ 14,417	$ 13,029
Accrued employee benefits costs	15,333	7,092
Accrued sales tax audit reserve	3,419	3,479
Rent expenses in excess of cash payments required	25,628	24,728
Deferred compensation	17,598	20,299
Workers' compensation insurance	9,900	9,153
General liability insurance	5,410	4,265
Lease exit obligations	2,010	1,829
Income tax credits	5,773	4,206
Other	9,160	6,997
	108,648	95,077
Tax liabilities:		
Inventory basis difference	(4,590)	(4,141)
Prepaid expenses	(1,912)	(1,423)
Depreciation	(87,417)	(65,650)
Amortization	(6,039)	(3,818)
Other	(2,083)	(1,551)
	(102,041)	(76,583)
Net deferred tax asset	$ 6,607	$ 18,494

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA made broad and complex changes to the U.S. tax code including, but not limited to, a reduction of the federal income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. This change required the Company to remeasure our deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future, which generally is 21% for federal income tax purposes. As permitted by the SEC Staff Accounting Bulletin 118, "Income Tax Accounting Implications of the Tax Cuts and Jobs Act", we recorded a provisional estimate of the effects of the TCJA on our existing deferred tax balances as of December 30, 2017, and recognized a provisional amount of $4.9 million, which was included as a component of income tax expense from continuing operations in fiscal 2017. We have subsequently finalized our accounting analysis based on the guidance, interpretations, and data available as of December 29, 2018. Adjustments made in the fourth quarter of fiscal 2018 upon finalization of our accounting analysis were not material to our Consolidated Financial Statements.

The Company has evaluated the need for a valuation allowance for all or a portion of the deferred tax assets. The Company believes that all of the deferred tax assets will more likely than not be realized through future earnings. The Company had state tax credit carryforwards of $5.7 million and $5.1 million as of December 29, 2018 and December 30, 2017, respectively, with varying dates of expiration between 2018 and 2030. The Company provided no valuation allowance as of December 29, 2018 and December 30, 2017 for state tax credit carryforwards, as the Company believes it is more likely than not that all of these credits will be utilized before their expiration dates.

Index

A reconciliation of the provision for income taxes to the amounts computed at the federal statutory rate is as follows (in thousands):

	Fiscal Year		
	2018	2017	2016
Tax provision at statutory rate	$143,511	$235,383	$240,894
Tax effect of:			
State income taxes, net of federal tax benefits	18,019	14,320	15,527
Section 162(m) limitation	2,581	1,223	633
Tax credits, net of federal tax benefits	(7,140)	(5,060)	(7,227)
Share-based compensation programs	(4,522)	(1,040)	—
Enactment of tax legislation	—	4,856	—
Other	(1,421)	242	1,323
Total income tax expense	$151,028	$249,924	$251,150

The Company and its affiliates file income tax returns in the U.S. and various state and local jurisdictions. With few exceptions, the Company is no longer subject to federal, state and local income tax examinations by tax authorities for years before 2014. Various states have completed an examination of our income tax returns for 2014 through 2016 with minimal adjustments.

The total amount of unrecognized tax positions that, if recognized, would decrease the effective tax rate, is $2.1 million at December 29, 2018. In addition, the Company recognizes current interest and penalties accrued related to these uncertain tax positions as interest expense, and the amount is not material to the Consolidated Statements of Income. The Company has considered the reasonably possible expected net change in uncertain tax positions during the next 12 months and does not expect any material changes to our liability for uncertain tax positions through December 28, 2019.

A reconciliation of the beginning and ending gross amount of unrecognized tax benefits (exclusive of interest and penalties) is as follows (in thousands):

	Fiscal Year		
	2018	2017	2016
Balance at beginning of year	$1,993	$1,579	$2,922
Additions based on tax positions related to the current year	621	527	460
Additions for tax positions of prior years	257	14	139
Reductions for tax positions of prior years	(420)	(127)	(1,829)
Reductions due to audit results	—	—	(113)
Balance at end of year	$2,451	$1,993	$1,579

Note 12 – Retirement Benefit Plans:

The Company has a defined contribution benefit plan, the Tractor Supply Company 401(k) Retirement Savings Plan (the “401(k) Plan”), which provides retirement benefits for eligible employees. The Company matches (in cash) 100% of the employee’s elective contributions up to 3% of eligible compensation plus 50% of the employee’s elective contributions from 3% to 6% of eligible compensation. In no event shall the total Company match made on behalf of the employee exceed 4.5% of the employee’s eligible compensation. All current contributions are immediately vested. Company contributions to the 401(k) Plan were approximately $8.5 million, $7.4 million, and $6.6 million during fiscal 2018, 2017, and 2016, respectively.

The Company offers, through a deferred compensation program, the opportunity for certain qualifying employees to elect to defer a portion of their annual base salary and/or their annual incentive bonus. Under the deferred compensation program, a percentage of the participants' salary deferral is matched by the Company, limited to a maximum annual matching contribution of $4,500. The Company's contributions, including accrued interest, were $0.6 million, $0.5 million, and $0.6 million during fiscal 2018, 2017, and 2016, respectively.

Index

Note 13 – Commitments and Contingencies:

Construction and Real Estate Commitments

At December 29, 2018, the Company had no material contractual commitments related to construction projects extending greater than twelve months.

Letters of Credit

At December 29, 2018, there were $33.5 million outstanding letters of credit under the 2016 Senior Credit Facility.

Litigation

The Company is involved in various litigation matters arising in the ordinary course of business. The Company believes that any estimated loss related to such matters has been adequately provided for in accrued liabilities to the extent probable and reasonably estimable. Accordingly, the Company currently expects these matters will be resolved without material adverse effect on its consolidated financial position, results of operations or cash flows.

Note 14 – Segment Reporting:

The Company has one reportable segment which is the retail sale of products that support the rural lifestyle. The following table indicates the percentage of net sales represented by each major product category during fiscal 2018, 2017, and 2016:

	Percent of Net Sales		
	Fiscal Year		
Product Category:	2018	2017	2016
Livestock and Pet	47 %	47 %	46 %
Hardware, Tools and Truck	22	22	22
Seasonal, Gift and Toy Products	19	19	19
Clothing and Footwear	8	8	8
Agriculture	4	4	5
Total	100%	100%	100%

Note 15 – New Accounting Pronouncements:

New Accounting Pronouncements Recently Adopted

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, “Revenue from Contracts with Customers (Topic 606).” ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements and converges areas under this topic with those of the International Financial Reporting Standards. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows from contracts with customers. Other major provisions include the capitalization and amortization of certain contract costs, ensuring the time value of money is considered in the transaction price, and allowing estimates of variable consideration to be recognized before contingencies are resolved in certain circumstances. In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date,” which implemented a one-year deferral of ASU 2014-09. As a result of the deferral, the amendments in ASU 2014-09 are effective for reporting periods beginning after December 15, 2017. In March 2016, the FASB issued ASU 2016-08, “Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net),” which further clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU 2016-10, “Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing,” which further clarifies the aspects of (a) identifying performance obligations and (b) the licensing implementation guidance. In May 2016, the FASB issued ASU 2016-12 “Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients,” which provides implementation guidance in regards to (a) assessing the collectability criterion, (b) the presentation of taxes collected from customers, (c) noncash consideration, (d) contract modification at transition, (e) completed contracts at transition and (f) other technical corrections. In December 2016, the FASB issued ASU 2016-20, “Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers,” which is intended to clarify the codification and to correct unintended application of guidance pertaining to Topic 606 and other Topics amended by ASU 2014-09 to increase stakeholders' awareness of the proposals and to expedite improvements to ASU 2014-09. The effective date and transition requirements for ASU 2016-08, ASU 2016-10, ASU 2016-12 and ASU 2016-20 are the same as the effective date and transition requirements of ASU 2014-09. Entities that transition to these standards may either retrospectively restate each prior reporting period or reflect the cumulative effect of initially applying the updates with an adjustment to retained earnings at the date of adoption. The Company adopted this guidance in the first quarter of fiscal 2018 using the modified retrospective transition method. Based on an evaluation of the standard as a whole, the Company identified customer incentives and principal versus agent considerations as the areas that were principally affected by the new revenue recognition guidance. The adoption of this guidance did not have a material impact on our Consolidated Financial Statements and related disclosures.

In May 2017, the FASB issued ASU 2017-09, "Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting." This update provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting in Topic 718. An entity should account for the effects of a modification unless (a) the fair value of the modified award is the same as the fair value of the original award immediately before the original award is modified, (b) the vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award is modified and (c) the classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified. The amendments in ASU 2017-09 are effective for public business entities for annual periods beginning after December 15, 2017, including interim periods within those annual periods. Early adoption is permitted, including adoption in any interim period, for public business entities for reporting periods for which financial statements have not been issued. The amendments in ASU 2017-09 should be applied prospectively to an award modified on or after the adoption date. The Company adopted this guidance in the first quarter of fiscal 2018. The adoption of this guidance did not have a material impact on our Consolidated Financial Statements and related disclosures.

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," which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. This guidance is effective for all entities for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. The amendments in ASU 2018-02 should be applied either in the period of adoption or retrospectively to each period in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company adopted this guidance in the first quarter of fiscal 2018 using a retrospective application, which resulted in the reclassification of $0.6 million from accumulated other comprehensive income to retained earnings in the Consolidated Balance Sheets, Consolidated Statements of Stockholders' Equity, and Consolidated Statements of Comprehensive Income as of and for the fiscal year ended December 30, 2017. No other periods presented were affected by the adoption of this accounting guidance.

In March 2018, the FASB issued ASU 2018-05, "Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118." The new guidance provides SEC Staff views on income tax accounting implications of the TCJA signed into law in December 2017. The guidance clarifies the measurement period timeframe, changes in subsequent reporting periods and reporting requirements as a result of the TCJA. The Company adopted this guidance in the first quarter of fiscal 2018. As further discussed in Note 11, the Company recorded a provisional impact of the TCJA in fiscal 2017. We have subsequently finalized our accounting analysis based on the guidance, interpretations, and data available as of December 29, 2018. Adjustments made in the fourth quarter of fiscal 2018 upon finalization of our accounting analysis were not material to our Consolidated Financial Statements.

New Accounting Pronouncements Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” This update requires a dual approach for lessee accounting under which a lessee will account for leases as finance leases or operating leases. Both finance leases and operating leases will result in the lessee recognizing a right-of-use asset and a corresponding lease liability on its balance sheet, with differing methodology for income statement recognition. In January 2018, the FASB issued ASU 2018-01, “Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842.” This update permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expired before the entity’s adoption of ASU 2016-02 and that were not accounted for as leases under previous lease guidance. In July 2018, ASU 2018-10, “Codification Improvements to Topic 842, Leases,” was issued to provide more detailed guidance and additional clarification for implementing ASU 2016-02. Furthermore, in July 2018, the FASB issued ASU 2018-11, “Leases (Topic 842): Targeted Improvements,” which provides an optional transition method in addition to the existing modified retrospective transition method by allowing a cumulative effect adjustment to the opening balance of retained earnings in the period of adoption. These new leasing standards are effective for public business entities for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. The Company intends to adopt this guidance in the first quarter of fiscal 2019 using the optional transition method provided by

Index

ASU 2018-11. We have made substantial progress in executing our implementation plan. We are electing the package of practical expedients, which among other things, allows us to carry forward our prior lease classifications under ASC 840. Adoption of the standard is expected to result in the recognition of additional right-of-use assets and lease liabilities for operating leases of approximately $2.0 billion to $2.2 billion. We are evaluating the disclosure requirements and are incorporating the collection of relevant data into our processes in preparation for disclosure in fiscal 2019. The Company does not expect the adoption of this guidance to have a material impact on its Consolidated Statements of Income, Comprehensive Income, Stockholders' Equity, or Cash Flows.

In August 2017, the FASB issued ASU 2017-12, "Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities," which amends and simplifies existing guidance in order to allow companies to more accurately present the economic effects of risk management activities in the financial statements. This update expands and refines hedge accounting for both nonfinancial and financial risk components and aligns the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. Additionally, the amendments in ASU 2017-12 provide new guidance about income statement classification and eliminates the requirement to separately measure and report hedge ineffectiveness. This guidance is effective for public business entities for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. The amendments in ASU 2017-12 require that an entity with cash flow or net investment hedges existing at the date of adoption apply a cumulative-effect adjustment to eliminate the separate measurement of ineffectiveness to the opening balance of retained earnings as of the beginning of the fiscal year in which the entity adopts this guidance. The amended presentation and disclosure guidance should be adopted prospectively. The Company is currently assessing the impact that adoption of this guidance will have on its Consolidated Financial Statements and related disclosures.

In June 2018, the FASB issued ASU 2018-07, "Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting," which expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. This guidance is effective for public business entities for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. The Company does not expect the adoption of this guidance to have a material impact on its Consolidated Financial Statements and related disclosures.

In August 2018, the FASB issued ASU 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement," which amends the disclosure requirements for fair value measurements by removing, modifying and adding certain disclosures. This guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2019, with early adoption permitted. The Company does not expect the adoption of this guidance to have a material impact on its Consolidated Financial Statements and related disclosures.

In August 2018, the FASB issued ASU 2018-15, "Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract." This update clarifies the accounting treatment for fees paid by a customer in a cloud computing arrangement (hosting arrangement) by providing guidance for determining when the arrangement includes a software license. This guidance is effective for public business entities for fiscal years, and interim periods within those years, beginning after December 15, 2019, with early adoption permitted. The amendments may be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently assessing the impact that adoption of this guidance will have on its Consolidated Financial Statements and related disclosures.

In October 2018, the FASB issued ASU 2018-16, "Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate (SOFR) Overnight Index Swap (OIS) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes" which expands the permissible benchmark interest rates to include the Secured Overnight

Financing Rate (SOFR) to be eligible as a U.S. benchmark interest rate for purposes of applying hedge accounting under Topic 815, Derivatives and Hedging. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted if an entity has previously adopted ASU 2017-12. The Company does not expect the adoption of this guidance to have a material impact on its Consolidated Financial Statements and related disclosures.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Index

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We carried out an evaluation required by the Securities Exchange Act of 1934, as amended (the “1934 Act”), under the supervision and with the participation of our principal executive officer and principal financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the 1934 Act) as of December 29, 2018. Based on this evaluation, our principal executive officer and principal financial officer concluded that, as of December 29, 2018, our disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

A report of the Company’s management on the Company’s internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the 1934 Act) and a report of Ernst & Young LLP, an independent registered public accounting firm, on the effectiveness of the Company’s internal control over financial reporting are included in Item 8 of this Annual Report on Form 10-K.

There were no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information set forth under the caption “Executive Officers of the Registrant” in Part I of this Form 10-K is incorporated herein by reference.

The information set forth under the captions “Item 1: Election of Directors,” “Board Meetings and Committees,” and “Section 16(a) Beneficial Ownership Reporting Compliance” in our Proxy Statement for our Annual Meeting of Stockholders to be held on May 9, 2019, is incorporated herein by reference.

The Company has a Code of Ethics which covers all exempt employees, officers and directors of the Company, including the principal executive officer, principal financial officer, principal accounting officer and controller. The Code of Ethics is available in the “Corporate Governance” section of the Company’s website at TractorSupply.com. A copy of the Code of Ethics can also be obtained, free of charge, upon written request to the Corporate Secretary, Tractor Supply Company, 5401 Virginia Way, Brentwood, TN 37027. The Company intends to post amendments to or waivers, if any, from its Code of Ethics (to the extent applicable to its principal executive officer, principal financial officer, principal accounting officer or controller) on its website.

Item 11. Executive Compensation

The information set forth under the captions “Corporate Governance – Compensation Committee Interlocks and Insider Participation,” “Compensation of Directors,” and “Executive Compensation” in our Proxy Statement for our Annual Meeting of Stockholders to be held on May 9, 2019, is incorporated herein by reference.

Index

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information set forth under the caption "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement for our Annual Meeting of Stockholders to be held on May 9, 2019, is incorporated herein by reference.

Following is a summary of our equity compensation plans as of December 29, 2018, under which equity securities are authorized for issuance, aggregated as follows:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights		Weighted Average Exercise Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance
Equity compensation plans approved by security holders:					
Stock Incentive Plans	4,532,766	(a)	$ 72.49	(b)	12,688,826
Employee Stock Purchase Plan	—		—		11,933,374
Equity compensation plans not approved by security holders	—		—		—
Total	4,532,766		$ 72.49		24,622,200

(a) Includes 4,053,386 outstanding stock options, 398,248 unvested restricted stock units and 39,822 restricted stock units which have vested but the receipt of which have been deferred by the recipient, and 41,310 unvested performance-based restricted share units. The 2006 Stock Incentive Plan was superseded in May 2009 by the 2009 Stock Incentive Plan. The 2009 Stock Incentive Plan was superseded in May 2018 by the 2018 Omnibus Incentive Plan. Shares available under the 2018 Omnibus Incentive Plan are reduced by one share for each share issued pursuant to the exercise of a stock option and by two shares for each share issued pursuant to a full-value award (e.g., restricted stock unit or performance-based restricted share unit).
(b) Excludes restricted stock units and performance-based restricted share units which have a weighted average exercise price of zero.

The information set forth in Note 2 to the Consolidated Financial Statements contained in this Form 10-K provides further information with respect to the material features of each plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information set forth under the captions "Corporate Governance – Director Independence and Board Operations" and "Related Party Transactions" in our Proxy Statement for our Annual Meeting of Stockholders to be held on May 9, 2019, is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information set forth under the caption "Item 2 – Ratification of Reappointment of Independent Registered Public Accounting Firm" in our Proxy Statement for our Annual Meeting of Stockholders to be held on May 9, 2019, is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) Financial Statements

See Consolidated Financial Statements under Item 8 on pages 39 through 70 of this Form 10-K.

(a) (2) Financial Statement Schedules

All schedules for which provision is made in the applicable accounting regulations of the SEC are not required under the related instructions, are inapplicable or the information is included in the Consolidated Financial Statements and, therefore, have been omitted.

Index

(a) (3) Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 75 through 77 of this Form 10-K, are incorporated herein by reference or filed as part of this Form 10-K.

Item 16. Form 10-K Summary

None.

Index

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TRACTOR SUPPLY COMPANY

Date: February 21, 2019	By:	/s/ Kurt D. Barton Executive Vice President – Chief Financial Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Kurt D. Barton Kurt D. Barton	Executive Vice President – Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 21, 2019
/s/ Gregory A. Sandfort Gregory A. Sandfort	Chief Executive Officer and Director (Principal Executive Officer)	February 21, 2019
/s/ Cynthia T. Jamison Cynthia T. Jamison	Chairman of the Board	February 21, 2019
/s/ Peter D. Bewley Peter D. Bewley	Director	February 21, 2019
/s/ Ricardo Cardenas Ricardo Cardenas	Director	February 21, 2019
/s/ Denise L. Jackson Denise L. Jackson	Director	February 21, 2019
/s/ Thomas A. Kingsbury Thomas A. Kingsbury	Director	February 21, 2019
/s/ Ramkumar Krishnan Ramkumar Krishnan	Director	February 21, 2019
/s/ George MacKenzie George MacKenzie	Director	February 21, 2019
/s/ Edna K. Morris Edna K. Morris	Director	February 21, 2019
/s/ Mark J. Weikel Mark J. Weikel	Director	February 21, 2019

Index

EXHIBIT INDEX

3.1	Restated Certificate of Incorporation, as amended, of the Company (filed as Exhibit 3.1 to Registrant's Annual Report on Form 10-K, filed with the Commission on February 29, 2012, Commission File No. 000-23314, and incorporated herein by reference).
3.2	Fifth Amended and Restated By-laws (filed as Exhibit 3.1(i) to Registrant's Current Report on Form 8-K, filed with the Commission on February 15, 2017, Commission File No. 000-23314, and incorporated herein by reference).
4.1	Form of Specimen Certificate representing the Company's Common Stock, par value $.008 per share (filed as Exhibit 4.2 to Amendment No. 1 to Registrant's Registration Statement on Form S-1, Registration No. 33-73028, filed in paper form with the Commission on January 31, 1994, and incorporated herein by reference).
10.1	Certificate of Insurance relating to the Medical Expense Reimbursement Plan of the Company (filed as Exhibit 10.33 to Registrant's Registration Statement on Form S-1, Registration No. 33-73028, filed in paper form with the Commission on December 17, 1993, and incorporated herein by reference).
10.2	Summary Plan Description of the Executive Life Insurance Plan of the Company (filed as Exhibit 10.34 to Registrant's Registration Statement on Form S-1, Registration No. 33-73028, filed in paper form with the Commission on December 17, 1993, and incorporated herein by reference).+
10.3	Tractor Supply Company 1996 Associate Stock Purchase Plan (filed as Exhibit 4.4 to Registrant's Registration Statement on Form S-8, Registration No. 333-10699, filed with the Commission on August 23, 1996, and incorporated herein by reference).+
10.4	Tractor Supply Company Restated 401(k) Retirement Plan (filed as Exhibit 4.1 to Registrant's Registration Statement on Form S-3, Registration No. 333-35317, filed with the Commission on September 10, 1997, and incorporated herein by reference).+
10.5	First Amendment, dated December 22, 2003 to the Tractor Supply Company Restated 401(k) Retirement Savings Plan (filed as Exhibit 10.53 to Registrant's Annual Report on Form 10-K, filed with the Commission on March 8, 2004, Commission File No. 000-23314, and incorporated herein by reference).+
10.6	Second Amendment to Tractor Supply Company Restated 401(k) Retirement Plan (filed as Exhibit 10.57 to Registrant's Annual Report on Form 10-K, filed with the Commission on March 23, 2001, Commission File No. 000-23314, and incorporated herein by reference).+
10.7	Trust Agreement (filed as Exhibit 4.2 to Registrant's Registration Statement on Form S-3, Registration No. 333-35317, filed with the Commission on September 10, 1997, and incorporated herein by reference).
10.8	Tractor Supply Company Executive Deferred Compensation Plan, dated November 11, 2001 (filed as Exhibit 10.58 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on May 13, 2002, Commission File No. 000-23314, and incorporated herein by reference).
10.9	Form of Incentive Stock Option Agreement under the 2006 Stock Incentive Plan (filed as Exhibit 10.39 to Registrant's Annual Report on Form 10-K, filed with the Commission on February 28, 2007, Commission File No. 000-23314, and incorporated herein by reference).+

10.10	Form of Incentive Stock Option Agreement under the 2006 Stock Incentive Plan (filed as Exhibit 10.45 to Registrant's Annual Report on Form 10-K, filed with the Commission on February 27, 2008, Commission File No. 000-23314, incorporated herein by reference).+
10.11	Tractor Supply Company 2006 Stock Incentive Plan (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 27, 2006, Commission File No. 000-23314 and incorporated herein by reference).+
10.12	Second Amendment to the Tractor Supply Company 2006 Stock Incentive Plan, effective February 8, 2007 (filed as Exhibit 10.38 to Registrant's Annual Report on Form 10-K, filed with the Commission on February 28, 2007, Commission File No. 000-23314, and incorporated herein by reference).+
10.13	Form of Incentive Stock Option Agreement under the 2006 Stock Incentive Plan (filed as Exhibit 10.41 to the Registrant's Annual Report on Form 10-K, filed with the Commission on February 25, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.14	Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 99.1 to Registrant's Current Report on Form 8-K, filed with the Commission on April 14, 2009, Commission File No. 000-23314, and incorporated herein by reference).+

Index

10.15	Form of Incentive Stock Option Agreement under the Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 10.44 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 4, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.16	Form of Restricted Share Unit Agreement under the Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 10.45 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 4, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.17	Form of Nonqualified Stock Option Agreement under the Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 10.46 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 4, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.18	Form of Director Restricted Stock Unit Award Agreement (filed as Exhibit 10.48 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on November 2, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.19	Form of Restricted Share Unit Agreement for Officers (filed as Exhibit 10.49 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on November 2, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.20	Form of Deferred Stock Unit Award Agreement for Directors (filed as Exhibit 10.50 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on November 2, 2009, Commission File No. 000-23314, and incorporated herein by reference).+
10.21	Compensation Recoupment Policy (filed as Exhibit 10.42 to Registrant's Quarterly Report on Form 10-Q, filed with the Commission on May 3, 2011, Commission File No. 000-23314, and incorporated herein by reference).+
10.22	Credit Agreement, dated as of October 24, 2011, by and among Tractor Supply Company, as Borrower, certain subsidiaries of the Company, certain lenders and Bank of America, N.A., as Administrative Agent for the lenders (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K, filed with the Commission on October 28, 2011, Commission File No. 000-23314, and incorporated herein by reference).
10.23	First Amendment to Credit Agreement and Increase of Revolving Committed Amount dated May 16, 2014, by and among Tractor Supply Company, as Borrower, certain subsidiaries of the Company, certain lenders and Bank of America, N.A., as Administrative Agent for the lenders (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K, filed with the Commission on May 21, 2014, Commission File No. 000-23314, and incorporated herein by reference).
10.24	First Amendment to the Tractor Supply Company 2009 Stock Incentive Plan, effective February 4, 2015 (filed as Exhibit 10.34 to the Registrant's Annual Report on Form 10-K, filed with the Commission on February 18, 2015, Commission File No. 000-23314, and incorporated herein by reference).+
10.25	Amended and Restated Employment Agreement, dated March 17, 2015, by and between Tractor Supply Company and Greg A. Sandfort (filed as Exhibit 10.2 to Registrant's Current Report on Form 8-K, filed with the Commission on March 18, 2015, Commission File No. 000-23314, and incorporated herein by reference).+
10.26	Transition Agreement dated January 27, 2016, by and between Tractor Supply Company and Lee J. Downing (filed as exhibit 10.37 to the Annual Report on Form 10-K, filed with the Commission on February 23, 2016, Commission No. 000-23314, and incorporated herein by reference).+

10.27	Credit Agreement, dated as of February 19, 2016, by and among Tractor Supply Company, as Borrower, certain subsidiaries of the Company, certain lenders and Wells Fargo Bank, National Association, as Administrative Agent and Regions Bank, as Syndication Agent, for the lenders (filed as Exhibit 10.1 to Current Report on Form 8-K, filed with the Commission on February 22, 2016, Commission File No. 000-23314, and incorporated herein by reference).
10.28	Transition Agreement dated November 14, 2016, by and between Tractor Supply Company and Anthony F. Crudele (filed as Exhibit 10.1 to the Current Report on Form 8-K, filed with the Commission on November 17, 2016, Commission File No. 000-23314, and incorporated herein by reference).+
10.29	Form of Change in Control Agreement, by and between Tractor Supply Company and each of Steve K. Barbarick, Chad M. Frazell, Robert D. Mills and Benjamin F. Parrish, Jr., dated March 1, 2017, and Kurt D. Barton, dated March 6, 2017 (filed as Exhibit 10.1 to Current Report on Form 8-K, filed with the Commission on March 7, 2017, Commission File No. 000-23314, and incorporated herein by reference).+
10.30	Incremental Term Loan Agreement, dated as of June 15, 2017, by and among Tractor Supply Company, as Borrower, certain subsidiaries of the Company, certain lenders and Wells Fargo Bank, National Association, as Administrative Agent and Regions Bank, as Syndication Agent, for the lenders (filed as Exhibit 10.1 to Current Report on Form 8-K, filed with the Commission on June 19, 2017, Commission File No. 000-23314, and incorporated herein by reference).

Index

10.31	Note Purchase and Private Shelf Agreement, dated August 14, 2017, by and among Tractor Supply Company, PGIM, Inc. ("Prudential") and certain of its affiliates (the "Prudential Affiliates") party thereto (filed as Exhibit 10.1 to Current Report on Form 8-K, filed with the Commission on August 16, 2017, Commission File No. 000-23314, and incorporated herein by reference).
10.32	Form of Performance Share Unit Agreement for Officers under the Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 10.33 to the Registrant's Annual Report on Form 10-K, filed with the Commission on February 22, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.33	Form of Performance Share Unit Agreement for the Chief Executive Officer under the Tractor Supply Company 2009 Stock Incentive Plan (filed as Exhibit 10.34 to the Registrant's Annual Report on Form 10-K, filed with the Commission on February 22, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.34	Tractor Supply Company 2018 Omnibus Incentive Plan (filed as Exhibit A to Registrant's Proxy Statement on Schedule 14A for Registrant's Annual Meeting of Shareholders held on May 10, 2018, filed with the Commission on March 27, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.35	Form of Nonqualified Stock Option Agreement under the Tractor Supply Company 2018 Omnibus Incentive Plan (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 9, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.36	Form of Restricted Share Unit Agreement under the Tractor Supply Company 2018 Omnibus Incentive Plan (filed as Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 9, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.37	Form of Performance Share Unit Agreement for Officers under the Tractor Supply Company 2018 Omnibus Incentive Plan (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q, filed with the Commission on August 9, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.38	Form of Indemnification Agreement, by and between Tractor Supply Company and each of its executive officers and directors, dated November 8, 2018 (filed as Exhibit 10.1 to Current Report on Form 8-K, filed with the Commission on November 14, 2018, Commission File No. 000-23314, and incorporated herein by reference).+
10.39*	Form of Performance Share Unit Agreement for Officers under the Tractor Supply Company 2018 Omnibus Incentive Plan.+
10.40*	Form of Performance Share Unit Agreement for Chief Executive Officer under the Tractor Supply Company 2018 Omnibus Incentive Plan.+
10.41*	Form of Restricted Share Unit Agreement under the Tractor Supply Company 2018 Omnibus Incentive Plan.+

10.42*	Form of Nonqualified Stock Option Agreement under the Tractor Supply Company 2018 Omnibus Incentive Plan.+
21*	List of subsidiaries.
23*	Consent of Ernst & Young LLP.
31.1*	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following financial information from our Annual Report on Form 10-K for fiscal 2018, filed with the SEC on February 21, 2019, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Balance Sheets at December 29, 2018 and December 30, 2017, (ii) the Consolidated Statements of Income for the fiscal years ended December 29, 2018, December 30, 2017, and December 31, 2016, (iii) the Consolidated Statements of Comprehensive Income for the fiscal years ended December 29, 2018, December 30, 2017, and December 31, 2016, (iv) the Consolidated Statements of Stockholders' Equity for the fiscal years ended December 29, 2018, December 30, 2017, and December 31, 2016, (v) the Consolidated Statements of Cash Flows for the fiscal years ended December 29, 2018, December 30, 2017, and December 31, 2016, and (vi) the Notes to Consolidated Financial Statements.

* Filed herewith
\+ Management contract or compensatory plan or arrangement

77