Real Industry, Inc.
Form 10-Q
November 09, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2015

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 001-08007

REAL INDUSTRY, INC.

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	46-3783818 (I.R.S. Employer Identification Number)
15301 Ventura Boulevard, Suite 400	
Sherman Oaks, California 91403 (Address of Principal Executive Offices)(Zip Code)	(805) 435-1255 (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. þ Yes ¨ No

Indicate by checkmark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Securities Exchange Act of 1934.

Large Accelerated Filer¨	Accelerated Filer þ
Non-Accelerated Filer ¨(Do not check if a smaller reporting company)	Smaller Reporting Company¨

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). ¨ Yes þ No

Indicate by check mark whether the Registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. þ Yes ¨ No

As of November 1, 2015, there were 28,891,766 shares of the Registrant’s common stock outstanding.

REAL INDUSTRY, INC.

QUARTERLY REPORT ON FORM 10-Q

For the Period Ended September 30, 2015

TABLE OF CONTENTS

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.
REAL INDUSTRY, INC.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except share and per share amounts)	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 44.9	$ 62.0
Trade accounts receivable, net	101.6	—
Financing receivable	47.6	—
Inventories	118.1	—
Deferred income taxes	0.1	5.1
Other current assets	14.4	1.0
Current assets of discontinued operations	0.1	18.0
Total current assets	326.8	86.1
Debt and equity offering costs	—	14.5
Property, plant and equipment, net	320.1	0.1
Intangible assets, net	20.6	0.1
Goodwill	85.0	—
Deferred income taxes	2.7	—
Other noncurrent assets	8.0	1.1
Noncurrent assets of discontinued operations	—	20.0
TOTAL ASSETS	$ 763.2	$ 121.9
LIABILITIES, REDEEMABLE PREFERRED STOCK AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Trade payables	$ 120.6	$ —
Accrued liabilities	39.0	7.1
Long-term debt due within one year	1.8	—
Deferred income taxes	0.4	—
Current liabilities of discontinued operations	0.6	8.1
Total current liabilities	162.4	15.2
Accrued pension benefits	46.3	—
Environmental liabilities	18.4	—
Long-term debt, net	347.9	—
Common stock warrant liability	7.6	5.6
Deferred income taxes	5.3	—
Other noncurrent liabilities	8.6	0.3
Noncurrent liabilities of discontinued operations	0.7	15.2
TOTAL LIABILITIES	597.2	36.3
Redeemable Preferred Stock, Series B; $1,000 liquidation preference per share; 100,000 and zero shares designated; 26,046 and zero shares issued and outstanding as of September 30, 2015 and December 31, 2014, respectively	21.2	—

Stockholders' equity:		
Preferred stock, Series A Junior Participating; $0.001 par value; 665,000 shares authorized; none issued or outstanding	—	—
Common stock, $0.001 par value, 66,500,000 shares authorized; 28,901,464 and 17,099,882 shares issued; and 28,891,766 and 17,099,882 shares outstanding as of September 30, 2015 and December 31, 2014, respectively	—	—
Additional paid-in capital	547.8	482.0
Accumulated deficit	(401.3)	(396.3)
Treasury stock, at cost; 9,698 and zero shares as of September 30, 2015 and December 31, 2014, respectively	(0.1)	—
Accumulated other comprehensive loss	(2.6)	—
Total stockholders' equity—Real Industry, Inc.	143.8	85.7
Noncontrolling interest	1.0	(0.1)
TOTAL STOCKHOLDERS' EQUITY	144.8	85.6
TOTAL LIABILITIES, REDEEMABLE PREFERRED STOCK AND STOCKHOLDERS' EQUITY	$ 763.2	$ 121.9

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

1

REAL INDUSTRY, INC.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per share amounts)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Revenues	$338.6	$—	$845.1	$0.1
Cost of sales	313.2	—	793.5	0.4
Gross profit (loss)	25.4	—	51.6	(0.3)
Selling, general and administrative expenses	16.5	3.8	39.8	8.8
Losses on derivative financial instruments	1.0	—	3.0	—
Amortization of intangibles	0.2	—	0.6	0.1
Other operating expense, net	0.3	—	1.2	—
Operating profit (loss)	7.4	(3.8)	7.0	(9.2)
Nonoperating expense (income):				
Interest expense, net	9.2	—	26.6	—
Change in fair value of common stock warrant liability	(3.4)	(2.4)	2.2	(3.4)
Acquisition-related costs and expenses	—	—	14.8	—
Other, net	(0.9)	—	(0.4)	0.3
Total nonoperating expense (income)	4.9	(2.4)	43.2	(3.1)
Earnings (loss) from continuing operations before income taxes	2.5	(1.4)	(36.2)	(6.1)
Income tax expense (benefit)	0.5	(0.7)	(6.7)	(1.9)
Earnings (loss) from continuing operations	2.0	(0.7)	(29.5)	(4.2)
Earnings (loss) from discontinued operations, net of income taxes	(0.7)	1.5	26.5	4.6
Net earnings (loss)	1.3	0.8	(3.0)	0.4
Earnings from continuing operations attributable to noncontrolling interest	0.1	—	0.3	—
Net earnings (loss) attributable to Real Industry, Inc.	$1.2	$0.8	$(3.3)	$0.4
EARNINGS (LOSS) PER SHARE				
Basic earnings (loss) per share:				
Continuing operations	$0.04	$(0.05)	$(1.21)	$(0.32)
Discontinued operations	(0.02)	0.11	1.02	0.35
Basic earnings (loss) per share	$0.02	$0.06	$(0.19)	$0.03
Diluted earnings (loss) per share:				
Continuing operations	$0.04	$(0.05)	$(1.21)	$(0.32)
Discontinued operations	(0.02)	0.11	1.02	0.35

Diluted earnings (loss) per share	$0.02	$0.06	$(0.19)	$0.03

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

REAL INDUSTRY, INC.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Net earnings (loss)	$1.3	$0.8	$(3.0)	$0.4
Other comprehensive loss:				
Current period currency translation adjustments	(1.7)	—	(2.6)	—
Comprehensive income (loss)	(0.4)	0.8	(5.6)	0.4
Comprehensive income attributable to noncontrolling interest	0.1	—	0.3	—
Comprehensive income (loss) attributable to Real Industry, Inc.	$(0.5)	$0.8	$(5.9)	$0.4

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

REAL INDUSTRY, INC.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities:		
Net earnings (loss)	$(3.0)	$0.4
Adjustments to reconcile net earnings (loss) to net cash provided by (used in) operating activities:		
Earnings from discontinued operations, net of income taxes	(26.5)	(4.6)
Depreciation and amortization	24.3	0.1
Deferred income tax benefit	(8.6)	—
Change in fair value of common stock warrant liability	2.2	(3.4)
Share-based compensation expense	1.0	1.0
Amortization of debt issuance costs	3.7	—
Unrealized losses on derivative financial instruments	0.8	—
Amortization of the fair value adjustment of acquired inventory	8.5	—
Other	1.0	0.8
Changes in operating assets and liabilities, net of the effects of acquisition	63.0	4.3
Net cash provided by (used in) operating activities of discontinued operations	(4.7)	0.2
Net cash provided by (used in) operating activities	61.7	(1.2)
Cash flows from investing activities:		
Acquisition of business, net of cash	(524.7)	—
Proceeds from sale of NABCO, net of $3.9 million held in escrow	74.0	—
Purchases of property and equipment	(18.6)	(0.1)
Other	(0.6)	—
Net cash used in investing activities of discontinued operations	—	(0.1)
Net cash used in investing activities	(469.9)	(0.2)
Cash flows from financing activities:		
Payment of NABCO outstanding debt	(14.3)	—
Proceeds from Asset-Based Facility, net of issuance costs	117.4	—
Payments on capital leases and the Asset-Based Facility	(64.2)	—
Proceeds from issuance of Senior Secured Notes, net of debt issuance costs	287.1	—
Proceeds from exercise of common stock options	1.1	—
Proceeds from issuance of common stock, net of issuance costs	63.3	—
Proceeds from exercise of Warrants	0.1	—
Other	0.1	0.2
Net cash used in financing activities of discontinued operations	(0.4)	(1.9)
Net cash provided by (used in) financing activities	390.2	(1.7)
Effect of exchange rate differences on cash and cash equivalents	—	—
Decrease in cash and cash equivalents	(18.0)	(3.1)
Cash and cash equivalents, beginning of period	63.0	48.0
Cash and cash equivalents, end of period	$45.0	$44.9
Cash and cash equivalents, end of period—continuing operations	$44.9	$44.6
Cash and cash equivalents, end of period—discontinued operations	0.1	0.3

Cash and cash equivalents, end of period	$45.0	$44.9

The accompanying notes are an integral part of these unaudited consolidated financial statements.

REAL INDUSTRY, INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—BUSINESS AND OPERATIONS

Real Industry, Inc. ("Real Industry," the "Company," "we," "us" or "our"), formerly known as Signature Group Holding, Inc., a holding company that owns all of the outstanding interests of its two primary operating companies, Real Alloy Intermediate Holding, LLC ("Real Alloy Parent") and SGGH, LLC ("SGGH"). Management expects to grow the Company through acquisitions, as well as through organic efforts within existing operations described below. Our current business strategy seeks to leverage our public company status, considerable federal net operating tax loss carryforwards ("NOLs") and the experience of our executive management team to acquire operating businesses at prices and on terms that are aligned with our growth plans.

During the first quarter of 2015, the Company underwent a considerable transformation. On January 9, 2015, we completed the sale of North American Breaker Co., LLC ("NABCO"), previously the primary business within SGGH. On February 27, 2015, we acquired the global recycling and specification alloys business (the "Real Alloy Business") of Aleris Corporation ("Aleris") (the "Real Alloy Acquisition"). A portion of the proceeds of the sale of NABCO were used to fund the Real Alloy Acquisition.

The Real Alloy Business, operating under Real Alloy Parent through its wholly owned subsidiary Real Alloy Holding, Inc. ("Real Alloy"), is a global leader in third-party aluminum recycling, which includes the processing of scrap aluminum and by-products and the manufacturing of wrought, cast and specification or foundry alloys. Real Alloy offers a broad range of products and services to wrought alloy processors, automotive original equipment manufacturers, and foundries and casters. Real Alloy's customers include companies that participate in or sell to the automotive, consumer packaging, steel and durable goods, aerospace, and building and construction industries. Real Alloy processes scrap aluminum and by-products and delivers recycled metal in liquid or solid form according to customer specifications. Real Alloy's facilities are capable of processing industrial (new) scrap, post-consumer (old/obsolete) scrap, and various aluminum by-products, providing a great degree of flexibility in reclaiming high-quality recycled aluminum. Real Alloy currently operates twenty-four facilities strategically located throughout North America and Europe and, as of September 30, 2015, had approximately 1,700 employees.

The closing of the Real Alloy Acquisition was the culmination of a series of equity and debt financing transactions that began in the fourth quarter of 2014, raising the capital required to fund the Real Alloy Acquisition and pay transaction costs as summarized below (collectively, the "Financings"):

- In October 2014, Real Industry issued 0.3 million shares of common stock at $10.00 per share to accredited investors in a private placement exempt from registration under the Securities Act of 1933, as amended (the "Securities Act"), providing gross proceeds of $3.0 million, which were used to fund a portion of the Real Alloy Acquisition;
- In December 2014, Real Industry issued approximately 4.4 million shares of common stock at $6.50 per share in an underwritten public offering providing gross proceeds of $28.5 million, which were used to fund a portion of the Real Alloy Acquisition;
- In January 2015, Real Alloy, as successor to SGH Escrow Corporation ("SGH Escrow"), issued $305.0 million in senior secured notes due January 15, 2019 (the "Senior Secured Notes") at a price of 97.206% of the principal amount, providing gross proceeds of $296.5 million, which were used to fund a portion of the Real Alloy Acquisition;
- In February 2015, Real Industry issued approximately 9.8 million shares of common stock to existing common stockholders in a stapled rights offering (the "Rights Offering"), providing gross proceeds of $55.0 million, of which $50.0 million was used to fund a portion of the Real Alloy Acquisition;

- In February 2015, the U.S., Canadian and German operating subsidiaries of Real Alloy entered into new credit facilities, including a $110.0 million asset-based lending facility (the “Asset-Based Facility”) secured by assets of certain of Real Alloy’s North American subsidiaries, and a €50.0 million factoring facility (the “Factoring Facility”) for the purchase of eligible accounts receivable of Real Alloy’s German operations. The initial draws on the Asset-Based Facility and Factoring Facility provided gross proceeds of $59.5 million and €25.0 million ($28.0 million), respectively, of which $73.5 million was used to fund a portion of the Real Alloy Acquisition and approximately $14.0 million was drawn for operating purposes; and
- In February 2015, Real Industry issued 25,000 shares, at a $1,000 liquidation preference per share, of a new series of non-participating preferred stock (the “Redeemable Preferred Stock”) to Aleris, as a portion of the purchase price for the Real Alloy Acquisition.

Additionally, Real Industry issued approximately 0.8 million shares of common stock to existing holders of warrants to purchase common stock in April 2015, as the final component of the Rights Offering launched in January 2015, which provided gross proceeds of $4.8 million.

On April 21, 2015, our common stock began trading on the Nasdaq Stock Exchange (“NASDAQ”) under the symbol “RELY” as part of the NASDAQ Global Select Market. On May 28, 2015, our stockholders approved an amendment to our charter to change our name to Real Industry, Inc. In June 2015, Real Industry became a member of the Russell Global®, Russell 3000® and Russell Microcap® indexes.

In June 2015, Real Industry commenced a controlled equity offering program, pursuant to which it issued approximately 0.2 million shares and 0.5 million shares of common stock in June and July, respectively, providing gross proceeds of $2.7 million and $5.5 million, respectively.

As a result of the transformative nature of the acquisition, divestiture and financing activities described above, our operations in 2015 have been and will be substantially different from that reported in the previous periods covered by this Quarterly Report on Form 10-Q (the “Report”). See Note 13—Segment Information for additional information about our reportable segments.

The assets and liabilities and results of operations of NABCO are included in discontinued operations for all periods presented as a result of its sale in the first quarter of 2015. Discontinued operations also includes certain assets and liabilities related to the former businesses of SGGH, then known as Fremont General Corporation (“Fremont”) and its primary operating subsidiary, Fremont Investment & Loan (“FIL”).

NOTE 2—FINANCIAL STATEMENT PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

The accompanying unaudited condensed consolidated financial statements comprise the accounts of Real Industry, its wholly owned and majority owned subsidiaries, and have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In the opinion of management, all adjustments, consisting of normal recurring adjustments considered necessary for a fair presentation, have been included. The Company evaluates subsequent events through the date of filing with the Securities and Exchange Commission (“SEC”). Operating results for the three and nine months ended September 30, 2015 are not indicative of the results that may be expected for the year ending December 31, 2015, as a result of the gain on sale associated with the NABCO sale, only seven months of operating performance of Real Alloy in the nine months ended September 30, 2015, the effects of purchase accounting, and acquisition costs associated with the Real Alloy Acquisition. These interim period unaudited condensed consolidated financial statements should be read in conjunction with the Company’s audited consolidated financial statements as of and for the year ended December 31, 2014, which are included in the Company’s Annual Report on Form 10-K, as filed with the SEC on March 16, 2015 (the “Annual Report”) and the Company’s recast 2014 audited consolidated financial statements (reflecting NABCO as a discontinued operation), which are included in the Company’s Current Report on Form 8-K filed with the SEC on October 6, 2015.

Certain amounts in the accompanying unaudited condensed consolidated financial statements have been reclassified to conform to the current presentation, including the classification of NABCO as a discontinued operation.

The Company’s significant accounting policies are disclosed in the consolidated financial statements included in Part IV, Item 15 of the Annual Report, which, as a result of the Real Alloy Acquisition, now include the following new and modified significant accounting policies.

Revenue recognition and shipping and handling costs

Revenues are recognized when title transfers and the risk of loss passes to the customer. This typically occurs when the goods reach their destination, depending on individual shipping terms. For customer-owned toll material, revenue is recognized upon the performance of the tolling service for the customers. For material that is consigned, revenue is not recognized until the product is used by the customer. Shipping and handling costs are included within cost of sales in the unaudited condensed consolidated statements of operations included elsewhere in this Report.

Accounts receivable allowances and credit risk

Credit is extended to our customers based on an evaluation of their financial condition; generally, collateral is not required. We maintain an allowance against our accounts receivable for the estimated probable losses on uncollectible accounts and sales returns and allowances. The allowance is based upon our historical loss experience, current economic conditions within the industries we serve as well as our determination of the specific risk related to certain customers. Accounts receivable are charged off against the reserve when, in management’s estimation, further collection efforts would not result in a reasonable likelihood of receipt, or later as proscribed by statutory regulations.

Financing receivable

A subsidiary of Real Alloy has an agreement to sell certain of its accounts receivable in Europe. Agreements that result in true sales of the transferred receivables, as defined in Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 860, Transfers and Servicing, which occur when receivables are transferred to a purchaser, without recourse to the Company, are reported as financing receivable in the unaudited condensed consolidated balance sheets until proceeds from such sales are received from the counterparty, and represents a Level 2 measurement in the fair value hierarchy. Cash proceeds received from such sales are included in operating cash flows.

The transferred receivables are isolated from the Real Alloy subsidiary's accounts, as debtors pay into a segregated escrow account maintained by the counterparty. The subsidiary maintains continuing involvement with the transferred receivables through limited servicing obligations, primarily related to recordkeeping. The subsidiary retains no right to the receivables, or associated collateral, and does not collect a servicing fee. Following transfer, the Company has no further rights to receive any cash flows or other benefits from the transferred receivables and has no further obligations to provide additional cash flows or other assets to any party related to the transfer.

Real Alloy transferred $117.6 million and $336.9 million of receivables during the three and nine months ended September 30, 2015, respectively. Administrative fees under the Factoring Facility associated with the transferred receivables were $0.2 million and $0.6 million during the three and nine months ended September 30, 2015, respectively, and are classified as selling, general and administrative expenses in the unaudited condensed consolidated statements of operations.

Inventories

Inventories are stated at the lower of cost or market. Cost is determined primarily on the average cost or specific identification method and includes material, labor and overhead related to the manufacturing process. The cost of inventories acquired in business combinations is recorded at fair value.

Property, plant and equipment

Property, plant and equipment is stated at cost, net of asset impairments and depreciation. The cost of property, plant and equipment acquired in business combinations represents the fair value of the acquired assets at the time of acquisition.

The estimated fair value of asset retirement obligations incurred after the Real Alloy Acquisition are capitalized to the related long-lived asset at the time the obligations are incurred and are depreciated over the estimated remaining useful life of the related asset.

Major renewals and improvements that extend an asset's useful life are capitalized to property, plant and equipment. Major repair and maintenance projects are expensed over periods not exceeding twenty-four months, while normal maintenance and repairs are expensed as incurred. Depreciation is primarily computed using the straight-line method over the estimated useful lives of the related assets, as follows:

	Estimated Useful Lives
Building and improvements	5 - 33 years
Production equipment and machinery	2 - 25 years
Office furniture, equipment and other	3 - 10 years

The construction costs of landfills used to store by-products of the recycling process are depreciated as space in the landfills is used based on the unit of production method. Additionally, used space in the landfill is determined periodically either by aerial photography or engineering estimates.

Goodwill

Goodwill is tested for impairment as of October 1 of each year and may be tested more frequently if changes in circumstances or the occurrence of events indicates that a potential impairment exists. We evaluate goodwill based upon our reporting units, which are defined as operating segments or, in certain situations, one level below the operating segment. As the purchase price allocation for the Real Alloy Acquisition is not yet finalized, the allocation of goodwill to our reporting units has not yet been finalized.

The impairment test is a two-step process, which requires us to make judgments in determining what assumptions to use in the calculations. The first step of the process consists of estimating the fair value of each reporting unit based on discounted cash flow models and guideline Company information, using revenue and profit forecasts, and comparing those estimated fair values with the carrying values, which include allocated goodwill. These projections include assumptions about prices, margins and other operating costs. Other key assumptions included in the fair value of our reporting units include estimated cash flow periods, terminal values based on our anticipated growth rate and the discount rate used, which is based on our current cost of capital, adjusted for the risks associated with our operations. If the determined fair value is less than the carrying value, a second step is performed to compute the amount of the impairment by determining an “implied fair value” of goodwill, which is compared to the corresponding carrying value.

Deferred financing costs

Costs related to the issuance of long-term debt are capitalized and classified as a reduction of the associated debt and amortized over the term of the related debt agreements as interest expense using the effective interest method. Costs related to the issuance of revolving credit facilities are capitalized and classified as other assets in the unaudited condensed consolidated balance sheets and are amortized over the term of the related credit facility on a straight-line basis as interest expense.

Derivatives and hedging

Real Alloy is engaged in activities that expose it to various market risks, including changes in the prices of aluminum alloys, scrap aluminum, copper, zinc and natural gas, as well as changes in currency exchange rates. Certain of these financial exposures are managed as an integral part of its risk management program, which seeks to reduce the potentially adverse effects that the volatility of the markets may have on operating results. Real Alloy may enter into forward contracts or swaps to manage the exposure to market risk. The fair value of these instruments is reflected in the unaudited condensed consolidated balance sheets and the impact of these instruments is reflected in the unaudited condensed consolidated statements of operations. Real Alloy does not hold or issue derivative financial instruments for trading purposes.

The estimated fair values of derivative financial instruments are recognized as assets or liabilities as of the balance sheet date. Fair values for metal and natural gas derivative financial instruments are determined based on the differences between contractual and forward rates of identical hedge positions as of the balance sheet date. In developing these fair values, Real Alloy includes an estimate of the risk associated with nonperformance by either its counterparty or itself.

Real Alloy does not account for its derivative financial instruments as hedges. The changes in fair value of derivative financial instruments and the associated gains and losses realized upon settlement are recorded in losses on derivative financial instruments in the unaudited condensed consolidated statements of operations. All realized gains and losses are included within net cash provided by operating activities in the unaudited condensed consolidated statements of cash flows. Real Alloy is exposed to losses in the event of nonperformance by its derivative counterparties. The counterparties’ creditworthiness is monitored on an ongoing basis, and credit levels are reviewed to ensure appropriate concentrations of credit outstanding to any particular counterparty. Although nonperformance by counterparties is possible, we do not currently anticipate nonperformance by any of these parties.

Currency translation

Certain of Real Alloy’s international subsidiaries use the local currency as their functional currency. Real Alloy translates all of the amounts included in the unaudited condensed consolidated statements of operations from its international subsidiaries into U.S. dollars at average monthly exchange rates, which management believes is representative of the actual exchange rates on the dates of the transactions. Additionally, Real Alloy maintains intercompany, long-term loans between its U.S. and foreign jurisdiction entities, which were established in the subsidiaries' functional currency and due to their long-term nature, any currency related effects are recorded as a component of accumulated other comprehensive loss. Adjustments resulting from the translation of the assets and liabilities into U.S. dollars at the balance sheet date exchange rates are reflected as a separate component of the Company's stockholders' equity. Currency translation adjustments accumulate in the Company's stockholders' equity until the disposition or liquidation of the international entities. Currency transactional gains and losses associated with receivables and payables denominated in currencies other than the functional currency are included within other, net in the unaudited condensed consolidated statements of operations. The translation of accounts receivables and payables denominated in currencies other than U.S. dollars resulted in transactional gains of $0.5 million and $0.4 million for the three and nine months ended September 30, 2015, respectively.

Environmental and asset retirement obligations

Environmental obligations that are not legal or contractual asset retirement obligations and that relate to existing conditions caused by past operations with no benefit to future operations are expensed, while expenditures that extend the life, increase the capacity or improve the safety of an asset, or mitigate or prevent future environmental contamination are capitalized in property, plant and equipment. Obligations are recorded when their occurrence is probable and the associated costs can be reasonably estimated. While accruals are based on management’s current best estimate of the future costs of remedial action, these liabilities can change substantially due to factors such as the nature and extent of contamination, changes in the required remedial actions and technological advancements. Existing environmental liabilities are not discounted to their present values, as the amount and timing of the expenditures are not fixed or reliably determinable.

Asset retirement obligations represent the present value of estimated future obligations associated with the retirement of tangible long-lived assets. Our asset retirement obligations relate primarily to capping our three landfills, as well as costs related to the future removal of asbestos and removal of underground storage tanks. The estimated fair value of such legal obligations is recognized in the period in which the obligations are incurred, and capitalized as part of the carrying amount of the associated long-lived asset. These estimated fair values are based upon the present value of future cash flows expected to be required to satisfy the obligations. Determining the estimated fair value of asset retirement obligations requires judgment, including estimates of the credit adjusted interest rate and estimates of future cash flows. Estimates of future cash flows are obtained primarily from engineering consulting firms. The present value of the obligations is accreted over time while the capitalized costs are depreciated over the estimated remaining useful life of the related asset.

Pension benefits

Pension benefit costs are accrued based on annual analyses performed by actuaries. These analyses are based on assumptions including a discount rate and the expected rate of return on plan assets. Both the discount rate and expected rate of return on plan assets require estimates and projections by management and can fluctuate from period to period. Real Alloy’s objective in selecting a discount rate is to select the best estimate of the rate at which the benefit obligations could be effectively settled. In making this estimate, projected cash flows are developed and matched with a yield curve based on an appropriate universe of high-quality corporate bonds. Assumptions for long-term rates of return on plan assets are based upon historical returns and future expectations for returns. See Note 3—Business Combinations for more information about the assumptions used to determine the pension benefit obligation as of the date of the Real Alloy Acquisition.

Management believes these assumptions are appropriate; however, the actuarial assumptions used to determine pension benefits may differ from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. Management does not believe differences in actual experience or reasonable changes in assumptions will materially affect the Company’s financial position or results of operations.

Recent accounting pronouncements

In September 2015, the FASB issued Accounting Standards Update (“ASU”) 2015-16, Business Combinations (Topic 805) (“ASU 2015-16”), which provides that an acquirer recognize adjustments to provisional amounts during the measurement period in which the adjustments are identified. ASU 2015-16 requires that an acquirer record, in the same period’s financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. ASU 2015-16 requires an entity to present separately on the face of the statements of operations, or disclose in the notes, the portion of the amount recorded in current period earnings, by line item, that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, and interim periods beginning after December 31, 2017. ASU 2015-16 will be applied prospectively to adjustments to provisional amounts that occur after the effective date, with earlier application permitted for financial statements that have not yet been made available for issuance. We do not anticipate that ASU 2015-16 will have a material impact on the Company’s financial statements.

In August 2015, the FASB issued ASU 2015-15, Interest—Imputation of Interest (Topic 835-30) (“ASU 2015-15”), which clarifies the SEC staff position on the presentation and recognition of debt issuance costs associated with line-of-credit arrangements. ASU 2015-15 provides that given the absence of authoritative guidance within ASU 2015-03, Interest—Interest Imputation (Subtopic 835-30) for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting the debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Company’s presentation of debt issuance costs associated with line-of-credit arrangements follows the guidance of ASU 2015-15.

In July 2015, the FASB issued ASU 2015-11, Inventory (Topic 330) ("ASU 2015-11"), which provides that an entity measure inventory at the lower of cost or net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. ASU 2015-11 will be effective for the Company on January 1, 2017, will be applied prospectively, and early adoption is permitted as of the beginning of an interim or annual period. We do not believe that the application of ASU 2015-11 will have a material impact on the Company's financial statements or disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which was the result of a joint project by the FASB and the International Accounting Standards Board to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and International Financial Reporting Standards. The issuance of a comprehensive and converged standard on revenue recognition is expected to enable financial statement users to better understand and consistently analyze an entity's revenue across industries, transactions and geographies. The standard will require additional disclosures to help financial statement users better understand the nature, amount, timing, and potential uncertainty of the revenue that is recognized. ASU 2014-09 will be effective for the Company on January 1, 2018, and will require either retrospective application to each prior reporting period presented or retrospective application with the cumulative effect of initially applying the standard recognized at the date of adoption. We are currently evaluating the impact the application of ASU 2014-09 will have on the Company's financial statements and disclosures.

NOTE 3—BUSINESS COMBINATIONS

On February 27, 2015, Real Industry, through its indirect wholly owned subsidiary, Real Alloy, acquired 100% of the voting interests of the Real Alloy Business from Aleris, under a purchase agreement (the "Real Alloy Purchase Agreement"). Upon closing, we paid $496.2 million to Aleris, and an additional $5.0 million of cash and the Redeemable Preferred Stock were placed into escrow to satisfy the indemnification obligations of Aleris under the Real Alloy Purchase Agreement, in which Aleris has agreed to indemnify Real Alloy and its affiliates for certain claims and losses. During the second quarter, we paid an additional $31.3 million of the purchase price representing the initial working capital adjustment under the Real Alloy Purchase Agreement. The final working capital adjustment totaled $2.4 million and was paid on September 3, 2015.

In addition, Real Alloy and Aleris have entered into a transition services agreement, under which Aleris will provide certain customary post-closing transition services, including information technology services, treasury services, accounts payable, cash management and payroll, credit/collection services, environmental services and human resource services, to Real Alloy, for periods ranging from three to twenty-four months following the acquisition date.

We incurred acquisition and financing-related costs and expenses associated with the Real Alloy Acquisition totaling approximately $14.8 million during the nine months ended September 30, 2015, which are classified as nonoperating expenses in the unaudited condensed consolidated statements of operations. Acquisition and financing-related costs and expenses associated with the Real Alloy Acquisition recognized in 2014 totaled $3.4 million.

The acquisition was accounted for as a business combination, with the purchase price allocated based on the estimated fair values of the assets acquired and liabilities assumed. The purchase price allocation remains preliminary as management continues to evaluate the assumptions and methodology used in the valuation of acquired inventories, property, plant and equipment, intangible assets, accrued pension benefits, environmental liabilities, asset retirement obligations, and the resultant deferred income tax adjustments.

(In millions)	
Purchase consideration:	
Consideration paid at closing	$501.2
Redeemable Preferred Stock issued	19.6
Initial working capital adjustment	31.3
Final working capital adjustment	2.4
Total purchase consideration	$554.5
Purchase price allocation:	
Assets:	
Cash	$10.2
Trade accounts receivable	150.1
Inventories	173.8
Property, plant and equipment	326.4
Deferred income taxes	6.1
Other	4.0
Identifiable intangible assets	21.1
Total assets	691.7
Liabilities:	
Trade payables	112.4
Accrued liabilities	26.9
Accrued pension liabilities	46.0
Environmental liabilities	18.4
Other	13.7
Deferred income taxes	4.8
Total liabilities	222.2
Estimated fair value of net assets acquired	$469.5
Total purchase consideration	$554.5
Estimated fair value of net assets acquired	469.5
Goodwill	$85.0

The estimated fair value of trade accounts receivable is based on the undiscounted receivables management expected to receive from the $150.4 million of total trade accounts receivable at the acquisition date. Due to the short-term nature of the receivables, the undiscounted receivables expected to be collected are estimated to approximate fair value.

Inventories include the estimated fair value of finished goods, work in process, raw material and supplies. The estimated fair value of finished goods was based on analyses of future selling prices and the profit associated with the manufacturing effort. The estimated fair value of work in process considered costs to complete to finished goods and was based on analyses of future selling prices and the profit associated with the manufacturing effort. The estimated fair value of raw materials and supplies was based on replacement cost. The $173.8 million of estimated fair value of inventories includes $10.6 million in fair value adjustments, of which $1.3 million and $8.5 million was amortized as noncash charges in cost of sales during the three and nine months ended September 30, 2015, respectively.

Property, plant and equipment includes land, site improvements, buildings and building improvements, and machinery, equipment, furniture and fixtures. The estimated fair value of property, plant and equipment was based on appraisals and replacement cost analyses.

The fair value of property, plant and equipment acquired was estimated as follows:

(In millions)	Estimated Fair Value
Land	$ 63.6
Buildings	57.0
Machinery, equipment, furniture and fixtures	193.8
Construction work in progress	12.0
Property, plant and equipment	$ 326.4

Identifiable intangible assets represent the estimated fair value of customer relationships and have an estimated useful life of 20 years. The valuation of the intangible assets acquired was based on management's estimates, available information, and reasonable and supportable assumptions. The fair value of these assets was estimated using the income approach. An excess earnings approach was used to estimate the fair value of the customer relationships. Significant assumptions used include forecasted revenues, customer retention rates and profit margins, a discount rate of 13.5% based on our overall cost of equity, adjusted for perceived business risks related to these customer relationships, and an estimated economic useful life of 20 years.

The fair value of trade payables was estimated to approximate carrying value due to the short-term nature of the liabilities. The fair value of accrued liabilities was estimated to approximate carrying value due to the short-term nature of the liabilities.

Accrued pension liabilities include defined benefit pension plans for the German employees. The plans are based on final pay and service, but some senior officers are entitled to receive enhanced pension benefits. Benefit payments are financed, in part, by contributions to a relief fund which establishes a life insurance contract to secure future pension payments. Based on statutory pension contributions calculations proscribed under German law, the plans are substantially underfunded. The unfunded accrued pension costs are covered under a pension insurance association under German law should Real Alloy, or its subsidiaries, be unable to fulfill their pension obligations.

The following assumptions were utilized to measure the accrued pension liabilities:

Discount rate	1.7%
Salary increase	3.0%
Pension increase	1.8%
Turnover	2.0%

Environmental liabilities represent estimated reserves for environmental remediation costs, which have been recognized based on the guidance in FASB ASC 450, Contingencies, and FASB ASC 410, Asset Retirement and Environmental Obligations. Real Alloy is subject to various environmental laws and regulations governing, among other things, the handling, disposal and remediation of hazardous substances and wastes and employee safety. Given the changing nature of environmental legal requirements, Real Alloy may be required to take environmental control measures at some of its facilities to meet future requirements.

The estimated fair value of the Redeemable Preferred Stock was determined based on a discounted cash flow using estimates of market rates and redemption probabilities. For more information on the Redeemable Preferred Stock, refer to Note 5—Debt, Other Financing Arrangements and Redeemable Preferred Stock and Note 12—Derivative and Other Financial Instruments and Fair Value Measurements.

Deferred income taxes represent the differences between the book and tax bases of the assets acquired. As a result of an election under section 338(h)(10) of the Internal Revenue Code of 1986, as amended (the "Tax Code"), the tax bases of U.S. assets acquired were adjusted to the acquisition date fair values.

Other liabilities assumed include asset retirement obligations, which represent obligations associated with the retirement of tangible long-lived assets. Assumed asset retirement obligations relate primarily to the requirement of capping three landfills, as well as costs related to the future removal of asbestos and costs to remove underground storage tanks. The estimated fair value is based upon the present value of the future cash flows expected to be required to satisfy the obligation using discount rates ranging from 6.7% to 13.2%. Determining the fair value of asset retirement obligations requires judgment, including estimates of the credit adjusted interest rate and estimates of future cash flows. The present value of the obligations is accreted over time.

Based on the estimated fair value of assets acquired and liabilities assumed, goodwill of $85.0 million is attributable to Real Alloy's strong management team, assembled workforce and its defensible market share. As the purchase price allocation for the Real Alloy Acquisition has not yet been finalized, the allocation of goodwill to our reporting units has not yet been finalized.

The following table reflects the activity associated with goodwill during the nine months ended September 30, 2015:

(In millions)	
Balance at beginning of period	$—
Preliminary purchase price allocation for the Real Alloy Acquisition reported as of March 31, 2015	102.3
Adjustments to preliminary purchase price allocation for the Real Alloy Acquisition recorded in the quarter ended June 30, 2015	(17.8)
Adjustments to preliminary purchase price allocation for the Real Alloy Acquisition recorded in the quarter ended September 30, 2015	0.5
Balance at end of period	$85.0

The operating results of Real Alloy are included in the Company's unaudited condensed consolidated financial statements from the acquisition date. For the period from the acquisition date to September 30, 2015, Real Alloy's total revenues and loss from continuing operations before income taxes were $845.0 million and $20.4 million, respectively.

The following selected unaudited pro forma results of operations of the Company for the three and nine months ended September 30, 2015 and 2014, give effect to this business combination as though the transaction occurred on January 1, 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2015	2014	2015	2014
Total revenues:				
As reported	$338.6	$—	$845.1	$0.1
Pro forma	338.6	392.6	1,081.9	1,165.6
Earnings (loss) from continuing operations before income taxes:				
As reported	$2.5	$(1.4)	$(36.2)	$(6.1)
Pro forma	3.0	(2.4)	(18.5)	(43.6)

NOTE 4—INVENTORIES

The following table presents the components of inventories as of September 30, 2015 and December 31, 2014:

(In millions)	September 30, 2015	December 31, 2014
Finished goods	$ 35.6	$ —
Raw materials and work in process	70.5	—
Supplies	12.0	—
Total inventories	$ 118.1	$ —

13

NOTE 5—DEBT, OTHER FINANCING ARRANGEMENTS AND REDEEMABLE PREFERRED STOCK

The following table presents the Company's long-term debt as of September 30, 2015 and December 31, 2014:

(In millions)	September 30, 2015	December 31, 2014
Senior Secured Notes:		
Principal amount outstanding	$ 305.0	$ —
Unamortized original issue discount and issuance costs	(14.7)	—
Senior Secured Notes, net	290.3	—
Asset-Based Facility:		
Principal amount outstanding	57.5	—
Unamortized debt issuance costs	(2.6)	—
Asset-Based Facility, net	54.9	—
Capital leases	4.5	—
Current portion of long-term debt	(1.8)	—
Total long-term debt, net	$ 347.9	$ —

Long-term debt

Senior Secured Notes

On January 8, 2015, Real Alloy, as successor to SGH Escrow, completed a private placement of $305.0 million aggregate principal of 10% Senior Secured Notes at a price of 97.206% of the principal amount thereof to qualified institutional purchasers in accordance with Rule 144A and Regulation S under the Securities Act. The Senior Secured Notes were issued pursuant to an indenture, dated as of January 8, 2015 (the "Indenture") between Real Alloy, as successor to SGH Escrow, Real Alloy Parent, and Wilmington Trust, National Association ("Wilmington"), as trustee and notes collateral trustee.

Under the terms of the Pledge and Security Agreement, dated as of February 27, 2015, by and between each of Real Alloy, Real Alloy Parent and the other parties signatory thereto and Wilmington as notes collateral trustee, the Senior Secured Notes and related guarantees are secured by first priority security interests in the fixed assets of Real Alloy, Real Alloy Parent and the Subsidiary Guarantors (as defined in the Pledge and Security Agreement) and by second priority security interests in certain other collateral of Real Alloy, Real Alloy Parent and the Subsidiary Guarantors.

The Indenture, among other things, limits Real Alloy and its restricted subsidiaries' (as defined in the Indenture) ability to: incur additional indebtedness or issue certain preferred stock; pay dividends or make other distributions on capital stock or prepay subordinated indebtedness; purchase or redeem any equity interests; make investments; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of its assets; engage in transactions with Real Alloy's affiliates; or enter into any sale and leaseback transactions. These covenants are subject to important exceptions and qualifications. As of September 30, 2015, Real Alloy was in compliance with all such covenants.

The Senior Secured Notes mature on January 15, 2019 and interest is payable on January 15 and July 15 of each year, commencing on July 15, 2015, through the date of maturity. For the three and nine months ended September 30, 2015, interest expense associated with the Senior Secured Notes was $8.7 million and $25.2 million, respectively, including $1.1 million and $3.2 million of noncash expense related to the amortization of the original issue discount and debt issuance costs, respectively, for the three and nine months ended September 30, 2015.

Asset-Based Facility

On February 27, 2015, a wholly owned domestic subsidiary of Real Alloy and an affiliate of Real Alloy entered into the $110.0 million Asset-Based Facility that matures on October 15, 2018. The Asset-Based Facility is secured by a first priority lien on the borrowers and, to the extent no adverse tax impact would be incurred, Real Alloy's foreign subsidiaries' accounts receivable, inventory, instruments representing receivables, guarantees and other credit enhancements related to receivables, and bank accounts into which receivables are deposited, among other related assets. The Asset-Based Facility is also secured by a second priority lien on the assets that secure the Senior Secured Notes. The borrowing base under the Asset-Based Facility is determined based on eligible accounts receivable and eligible inventory. U.S. dollar denominated loans under the U.S. Sub-facility will bear interest, at the borrowers' option, either (i) at 1, 2, 3 or 6-month interest periods at LIBOR, or (ii) the Base Rate (as defined below), in each case plus a margin based on the amount of the excess availability under the Asset-Based Facility. The "Base Rate" is equal to the greater of (a) the U.S. prime rate, (b) the U.S. Federal Funds Rate plus 50 basis points, and (c) the sum of LIBOR plus a margin based on the amount of the excess availability under the Asset-Based Facility. Canadian dollar denominated loans under the Canadian Sub-facility will bear interest, at the borrowers' option, either (i) at 1, 2, 3 or 6-month interest periods at an average Canadian interbank rate, or (ii) floating at the greater of the Canadian prime rate or the average 30-day Canadian interbank rate plus 1.35%, in each case plus a margin based on the amount of the excess availability under the Asset-Based Facility. Events of default will trigger an increase of 2.0% in all interest rates. Interest is payable monthly in arrears, except for LIBOR loans and Canadian interbank rate loans, for which interest is payable at the end of each relevant interest period. On the initial funding date, the borrowers paid a 1.0% funding fee. For the three and nine months ended September 30, 2015, interest expense associated with the Asset-Based Facility was $0.5 million and $1.1 million, respectively, including $0.2 million and $0.5 million related to the amortization of debt issuance costs, respectively. As of September 30, 2015, the borrowers were in compliance with all applicable covenants under the Asset-Based Facility.

Capital Leases

As part of the Real Alloy Acquisition, existing capital leases of the Real Alloy Business, primarily mobile and office equipment, were assumed. In the normal course of operations, Real Alloy enters into capital leases to finance office and other equipment for its operations. As of September 30, 2015, $1.8 million of the $4.5 million in capital lease obligations are due within the next twelve months.

Factoring Facility

On February 27, 2015, an indirect wholly owned German subsidiary of Real Alloy, entered into the €50 million Factoring Facility, which provides for nonrecourse sales of certain of its accounts receivables to a financial institution, subject to certain limitations and eligibility requirements. The Factoring Facility has a termination date of January 15, 2019.

Prior to the collection of proceeds from the transferred receivables, advances against such proceeds are available to the Real Alloy subsidiary, subject to certain limitations and eligibility requirements. Such advances, which totaled $4.4 million as of September 30, 2015, are recorded as a reduction to the financing receivable in the unaudited condensed consolidated balance sheets, due to the counterparty's right of set off.

The interest rate applicable to advances under the Factoring Facility is the three-month EURIBOR (daily rate) fixed on the last business day of a month for the following month, plus 1.65%. Interest expense on advances was $0.1 million for the nine months ended September 30, 2015.

Redeemable Preferred Stock

The Redeemable Preferred Stock was issued to Aleris on February 27, 2015 as a portion of the purchase price for the Real Alloy Acquisition. The Redeemable Preferred Stock pays quarterly dividends at a rate of 7% for the first 18 months after the date of issuance, 8% for the next 12 months, and 9% thereafter. Dividends may be paid in kind for the first two years, and thereafter will be paid in cash. All accrued and accumulated dividends on the Redeemable Preferred Stock will be prior and in preference to any dividend on any of the Company's common stock or other junior securities.

The shares of Redeemable Preferred Stock are generally non-voting, however the consent of the holders of a majority of the outstanding shares of Redeemable Preferred Stock are required, among other requirements, (i) until the second anniversary of issuance, to (x) declare or pay cash dividends on Real Industry common stock; or (y) purchase, redeem or acquire shares of Real Industry common stock, other than, among others, certain shares of common stock issued to employees; (ii) so long as at least $10.0 million in aggregate principal amount of Redeemable Preferred Stock is outstanding, to make acquisitions valued at more than 5% of the consolidated assets of the Company and its subsidiaries; (iii) to take actions that would adversely affect the rights of the holders of the Redeemable Preferred Stock; and (iv) to undertake certain merger activities unless the Redeemable Preferred Stock remains outstanding or is purchased at the liquidation preference.

The Company may generally redeem the shares of Redeemable Preferred Stock at any time at the liquidation preference, and the holders may require the Company to redeem their shares of Redeemable Preferred Stock at the liquidation preference upon a change of control under the Senior Secured Notes (or any debt facility that replaces or redeems the Senior Secured Notes) to the extent that the change of control does not provide for such redemption at the liquidation preference. A holder of Redeemable Preferred Stock may require the Company to redeem all, but not less than all, of such holder's Redeemable Preferred Stock sixty-six months after the issuance date. In addition, the Company may redeem shares of Redeemable Preferred Stock to the extent Aleris is required to indemnify the Company under the Real Alloy Purchase Agreement for the Real Alloy Acquisition. The Redeemable Preferred Stock held by Aleris and its subsidiaries has a liquidation preference of $26.0 million, as of September 30, 2015, and is not transferrable (other than to another subsidiary of Aleris) for eighteen months following issuance (or such longer period in connection with any ongoing indemnity claims under the Real Alloy Purchase Agreement).

The carrying value of Redeemable Preferred Stock is based on the estimated fair value of the instrument as of the issuance date. The difference between the redemption value and the estimated fair value as of the issuance date is being accreted to the redemption value over the period preceding the holder’s right to redeem the instrument, or sixty-six months, using the effective interest method.

The following table presents the activity related to the carrying value of Redeemable Preferred Stock during the nine months ended September 30, 2015:

(In millions)	
Balance at beginning of period	$—
Issuance of Redeemable Preferred Stock	19.6
Dividends and accretion	1.6
Balance at end of period	$21.2

NOTE 6—COMMON STOCK WARRANT LIABILITY

On June 11, 2010, warrants to purchase an aggregate of 1.5 million shares of Real Industry’s common stock were issued (the “Warrants”). The aggregate purchase price for the Warrants was $0.3 million, due in equal installments as the Warrants vested, 20% upon issuance and, thereafter, 20% annually on the anniversary of the issuance date and, as of June 30, 2015, the Warrants are 100% vested. The Warrants expire in June 2020 and had an original exercise price of $10.30 per share. The Warrants were issued without registration in reliance on the exemption set forth in Section 4(a)(2) of the Securities Act.

The Warrants include customary terms that provide for certain adjustments of the exercise price and the number of shares of common stock to be issued upon the exercise of the Warrants in the event of stock splits, stock dividends, pro rata distributions and certain other fundamental transactions. Additionally, the Warrants are subject to pricing protection provisions. During the term of the Warrants, the pricing protection provisions provide that certain issuances of new shares of common stock at prices below the current exercise price of the Warrants automatically reduce the exercise price of the Warrants to the lowest per share purchase price of common stock issued. In February 2015, the Company issued shares of common stock in the Rights Offering at $5.64 per share, thereby reducing the exercise price of the Warrants to $5.64 per share as of September 30, 2015.

In May 2015, 15,000 Warrants were exercised, including 7,500 on a cashless basis, resulting in the issuance of 9,360 shares of common stock and gross proceeds of $0.1 million. In September 2015, 16,667 Warrants were exercised on a cashless basis, resulting in the issuance of 6,969 shares of common stock. Upon exercise, the fair value of the Warrants exercised are reclassified to additional paid-in capital. As of September 30, 2015, 1,468,333 Warrants remain outstanding.

The Company utilizes a Monte Carlo simulation to estimate the fair value of the common stock warrant liability as of September 30, 2015 and December 31, 2014. See Note 12—Derivative and Other Financial Instruments and Fair Value Measurements for a discussion about the estimated fair values determined using the Monte Carlo simulation option pricing model. A decrease in the common stock warrant liability results in other nonoperating income, while an increase in the common stock warrant liability results in other nonoperating expense. The following table presents changes in the fair value of the common stock warrant liability during the three and nine months ended September 30, 2015 and 2014:

(In millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Balance at beginning of period	$11.1	$8.3	$5.6	$9.3
Warrants exercised	(0.1)	—	(0.2)	—
Change in fair value of common stock warrant liability	(3.4)	(2.4)	2.2	(3.4)
Balance at end of period	$7.6	$5.9	$7.6	$5.9

NOTE 7—STOCKHOLDERS' EQUITY AND NONCONTROLLING INTEREST

The following table summarizes the activity within stockholders' equity and noncontrolling interest for the nine months ended September 30, 2015:

(In millions)	Equity Attributable to Real Industry, Inc.	Noncontrolling Interest	Total Equity		
Balance at beginning of period	$ 251,138	—	252,868	——	252,868
Non U.S. corporate bonds	46,245	—	46,611	——	46,611
Equity securities:					
U.S. equities	258,075	509,564	—	——	509,564
Non U.S. equities	152,575	224,139	—	——	224,139
Total	$ 1,555,425	$ 985,896	$ 344,423	$—$726,413	$2,056,732

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $131.8 million of equity investments in unconsolidated subsidiaries and $111.7 million of rabbi trust assets and miscellaneous investments.

(b) Due to limited availability of published pricing and a lack of immediate redeemability, certain fund investments measured at NAV are not required to be categorized within the fair value hierarchy.

	Dec. 31, 2016					
		Fair Value				
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV (b)	Total
Nuclear decommissioning fund (a)						
Cash equivalents	$20,379	$20,379	$—	$ —	$ —	$20,379
Commingled funds:						
Non U.S. equities	260,877	133,126	—	—	112,233	245,359
Emerging market debt funds	93,597	—	—	—	97,543	97,543
Commodity funds	106,571	—	—	—	92,091	92,091
Private equity investments	132,190	—	—	—	190,462	190,462
Real estate	128,630	—	—	—	187,647	187,647
Other commingled funds	151,048	—	—	—	159,489	159,489
Debt securities:						
Government securities	32,764	—	31,965	—	—	31,965
U.S. corporate bonds	104,913	—	105,772	—	—	105,772
Non U.S. corporate bonds	21,751	—	21,672	—	—	21,672
Municipal bonds	13,609	—	13,786	—	—	13,786
Mortgage-backed securities	2,785	—	2,816	—	—	2,816
Equity securities:						
U.S. equities	270,779	473,400	—	—	—	473,400
Non U.S. equities	189,100	218,381	—	—	—	218,381
Total	$1,528,993	$845,286	$176,011	$ —	$ 839,465	$1,860,762

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $132.8 million of equity investments in unconsolidated subsidiaries and $98.3 million of rabbi trust assets and miscellaneous investments.

(b) Due to limited availability of published pricing and a lack of immediate redeemability, certain fund investments measured at NAV are not required to be categorized within the fair value hierarchy.

Table of Contents

For the three and nine months ended Sept. 30, 2017 and 2016 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, as of Sept. 30, 2017:

(Thousands of Dollars)	Final Contractual Maturity Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$1,275	$2,303	$41,366	$44,944
U.S. corporate bonds	3,834	64,119	150,741	34,174	252,868
Non U.S. corporate bonds	—	13,793	26,651	6,167	46,611
Debt securities	$3,834	$79,187	$179,695	$81,707	$344,423

Rabbi Trusts

In June 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following tables present the cost and fair value of the assets held in rabbi trusts as of Sept. 30, 2017 and Dec. 31, 2016:

	Sept. 30, 2017				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$11,227	$11,227	$ —	$ —	$11,227
Mutual funds	46,368	48,944	—	—	48,944
Total	$57,595	$60,171	$ —	$ —	$60,171

	Dec. 31, 2016				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$47,831	$47,831	$ —	$ —	$47,831
Mutual funds	1,663	1,901	—	—	1,901
Total	$49,494	$49,732	$ —	$ —	$49,732

[a] Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

Table of Contents

As of Sept. 30, 2017, accumulated other comprehensive losses related to interest rate derivatives included $2.6 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

As of Sept. 30, 2017, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2018. Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three and nine months ended Sept. 30, 2017 and 2016.

As of Sept. 30, 2017, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs as of Sept. 30, 2017 and Dec. 31, 2016:

(Amounts in Thousands) [(a)(b)]	Sept. 30, 2017	Dec. 31, 2016
Megawatt hours of electricity	78,733	46,773
Million British thermal units of natural gas	62,279	121,978
Gallons of vehicle fuel	300	—

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Table of Contents

The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2017 and 2016, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,579 (a)	$—	$ —
Vehicle fuel and other commodity	38	—	(11) (b)	—	—
Total	$38	$—	$1,568	$—	$ —
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$ 1,282 (c)
Electric commodity	—	17,750	—	(3,122) (d)	—
Natural gas commodity	—	(2,076)	—	—	—
Total	$—	$ 15,674	$—	$ (3,122)	$ 1,282

	Nine Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$4,257 (a)	$—	$ —
Vehicle fuel and other commodity	81	—	(16) (b)	—	—
Total	$81	$—	$4,241	$—	$ —
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$ 8,069 (c)
Electric commodity	—	17,245	—	(9,435) (d)	—
Natural gas commodity	—	(9,921)	—	1,075 (e)	(4,070) (e)
Total	$—	$ 7,324	$—	$ (8,360)	$ 3,999

Three Months Ended Sept. 30, 2016

(Thousands of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Regulatory (Assets) and Liabilities	Pre-Tax Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Pre-Tax Losses Reclassified into Income During the Period from: Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$ —	$1,502 (a)	$ —	$ —
Vehicle fuel and other commodity	(6)	—	46 (b)	—	—
Total	$(6)	$ —	$1,548	$ —	$ —
Other derivative instruments					
Commodity trading	$—	$ —	$—	$ —	$ 1,779 (c)
Electric commodity	—	15,497	—	2,491 (d)	—
Natural gas commodity	—	(5,737)	—	—	(6) (e)
Total	$—	$ 9,760	$—	$ 2,491	$ 1,773

27

Table of Contents

	Nine Months Ended Sept. 30, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$4,470 (a)	$ —	$ —
Vehicle fuel and other commodity	7	—	150 (b)	—	—
Total	$7	$—	$4,620	$ —	$ —
Other derivative instruments					
Commodity trading	$—	$—	$—	$ —	$ 3,269 (c)
Electric commodity	—	14,528	—	30,024 (d)	—
Natural gas commodity	—	(2,376)	—	11,666 (e)	(5,005) (e)
Total	$—	$ 12,152	$—	$ 41,690	$ (1,736)

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to operating and maintenance (O&M) expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Certain derivatives are utilized to mitigate natural gas price risk for electric generation and are recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Amounts for the three and nine months ended Sept. 30, 2017 included no settlement gains or losses and $0.9 million of settlement gains, respectively. Amounts for the three and nine months ended Sept. 30, 2016 included no settlement gains or losses. The remaining derivative settlement gains and losses for the three and nine months ended Sept. 30, 2017 and 2016 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These gains and losses are subject to cost-recovery and reclassified out of income to a regulatory asset or liability, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2017 and 2016. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

Table of Contents

Xcel Energy’s utility subsidiaries’ most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. As of Sept. 30, 2017, three of Xcel Energy’s 10 most significant counterparties for these activities, comprising $36.1 million or 22 percent of this credit exposure, had investment grade credit ratings from Standard & Poor’s, Moody’s or Fitch Ratings. Six of the 10 most significant counterparties, comprising $44.2 million or 27 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy’s internal analysis, had credit quality consistent with investment grade. The one remaining significant counterparty, comprising of $8.1 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. Nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary’s credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies or for cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Sept. 30, 2017 and Dec. 31, 2016, there were no derivative instruments in a material liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary’s ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2017 and Dec. 31, 2016.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy’s derivative assets and liabilities measured at fair value on a recurring basis as of Sept. 30, 2017:

	Sept. 30, 2017					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$56	$—	$56	$ —	$56
Other derivative instruments:						
Commodity trading	1,412	12,172	86	13,670	(6,692)	6,978
Electric commodity	—	—	62,951	62,951	(2,841)	60,110
Natural gas commodity	—	1,898	—	1,898	(135)	1,763
Total current derivative assets	$1,412	$14,126	$63,037	$78,575	$ (9,668)	68,907
PPAs [(a)]						5,626
Current derivative instruments						$74,533
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$11	$—	$11	$ —	$11
Other derivative instruments:						
Commodity trading	84	30,613	5,661	36,358	(7,574)	28,784
Total noncurrent derivative assets	$84	$30,624	$5,661	$36,369	$ (7,574)	28,795
PPAs [(a)]						20,329

Noncurrent derivative instruments	$49,124

29

Table of Contents

(Thousands of Dollars)	Sept. 30, 2017 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$1,289	$10,204	$3	$11,496	$ (7,495)	$4,001
Electric commodity	—	—	2,842	2,842	(2,841)	1
Natural gas commodity	—	962	—	962	(135)	827
Total current derivative liabilities	$1,289	$11,166	$2,845	$15,300	$ (10,471)	4,829
PPAs [a]						22,830
Current derivative instruments						$27,659
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$52	$23,072	$—	$23,124	$ (10,239)	$12,885
Total noncurrent derivative liabilities	$52	$23,072	$—	$23,124	$ (10,239)	12,885
PPAs [a]						118,173
Noncurrent derivative instruments						$131,058

(a) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2017. At Sept. 30, 2017, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $3.5 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2016:

(Thousands of Dollars)	Dec. 31, 2016 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$13,179	$14,105	$—	$27,284	$ (20,637)	$6,647
Electric commodity	—	—	19,251	19,251	(1,976)	17,275
Natural gas commodity	—	8,839	—	8,839	—	8,839
Total current derivative assets	$13,179	$22,944	$19,251	$55,374	$ (22,613)	32,761
PPAs [a]						5,463
Current derivative instruments						$38,224
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$100	$31,029	$—	$31,129	$ (7,323)	$23,806
Natural gas commodity	—	1,652	—	1,652	—	1,652
Total noncurrent derivative assets	$100	$32,681	$—	$32,781	$ (7,323)	25,458
PPAs [a]						24,731

Noncurrent derivative instruments	$50,189

Table of Contents

(Thousands of Dollars)	Dec. 31, 2016 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$13,787	$11,320	$22	$25,129	$ (20,974)	$4,155
Electric commodity	—	—	1,976	1,976	(1,976)	—
Total current derivative liabilities	$13,787	$11,320	$1,998	$27,105	$ (22,950)	4,155
PPAs [a]						22,804
Current derivative instruments						$26,959
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$89	$23,424	$—	$23,513	$ (10,727)	$12,786
Total noncurrent derivative liabilities	$89	$23,424	$—	$23,513	$ (10,727)	12,786
PPAs [a]						135,360
Noncurrent derivative instruments						$148,146

(a) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $3.7 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2017 and 2016:

(Thousands of Dollars)	Three Months Ended Sept. 30 2017	2016
Balance at July 1	$69,237	$24,517
Purchases	—	274
Settlements	(33,144)	(33,982)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	548	9
Net gains recognized as regulatory assets and liabilities	29,212	33,777
Balance at Sept. 30	$65,853	$24,595

(Thousands of Dollars)	Nine Months Ended Sept. 30 2017	2016
Balance at Jan. 1	$17,253	$18,028
Purchases	80,073	33,296
Settlements	(75,121)	(60,707)

Net transactions recorded during the period:		
Gains (losses) recognized in earnings [a]	5,769	(33)
Net gains recognized as regulatory assets and liabilities	37,879	34,011
Balance at Sept. 30	$65,853	$24,595

[a] These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2017 and 2016.

Table of Contents

Fair Value of Long-Term Debt

As of Sept. 30, 2017 and Dec. 31, 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	Sept. 30, 2017 Carrying Amount	Sept. 30, 2017 Fair Value	Dec. 31, 2016 Carrying Amount	Dec. 31, 2016 Fair Value
Long-term debt, including current portion	$14,878,382	$16,192,542	$14,450,247	$15,513,209

The fair value of Xcel Energy’s long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Sept. 30, 2017 and Dec. 31, 2016, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

9. Other Income, Net

Other income, net consisted of the following:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	2017	2016	2017	2016
Interest income	$5,772	$1,385	$11,679	$6,439
Other nonoperating income	—	341	5,013	2,517
Insurance policy expense	(528)	(1,148)	(2,549)	(2,568)
Other nonoperating expense	(155)	—	—	—
Other income, net	$5,089	$578	$14,143	$6,388

10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy’s chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy’s regulated electric utility segment generates, transmits and distributes electricity primarily in portions of Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy’s regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $131.8 million and $132.8 million as of Sept. 30, 2017 and Dec. 31, 2016, respectively, included in the regulated natural gas utility segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Table of Contents

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2017					
Operating revenues from external customers	$2,783,569	$214,253	$19,075	$ —	$3,016,897
Intersegment revenues	351	378	—	(729)	—
Total revenues	$2,783,920	$214,631	$19,075	$ (729)	$3,016,897
Net income (loss)	$503,058	$1,853	$(12,770)	$ —	$492,141

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2016					
Operating revenues from external customers	$2,799,964	$221,956	$18,227	$ —	$3,040,147
Intersegment revenues	282	292	—	(574)	—
Total revenues	$2,800,246	$222,248	$18,227	$ (574)	$3,040,147
Net income (loss)	$479,399	$(5,297)	$(16,307)	$ —	$457,795

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2017					
Operating revenues from external customers	$7,420,646	$1,129,795	$57,806	$ —	$8,608,247
Intersegment revenues	1,081	927	—	(2,008)	—
Total revenues	$7,421,727	$1,130,722	$57,806	$ (2,008)	$8,608,247
Net income (loss)	$924,773	$77,946	$(44,045)	$ —	$958,674

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2016					
Operating revenues from external customers	$7,209,225	$1,046,544	$56,500	$ —	$8,312,269
Intersegment revenues	1,038	820	—	(1,858)	—
Total revenues	$7,210,263	$1,047,364	$56,500	$ (1,858)	$8,312,269
Net income (loss)	$863,076	$84,974	$(52,148)	$ —	$895,902

11. Earnings Per Share

Basic earnings per share (EPS) was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements. Common stock equivalents causing a dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

Table of Contents

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows:

	Three Months Ended Sept. 30, 2017			Three Months Ended Sept. 30, 2016		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$492,141	—	—	$457,795	—	—
Basic EPS:						
Earnings available to common shareholders	492,141	508,581	$ 0.97	457,795	508,941	$ 0.90
Effect of dilutive securities:						
Time based equity awards	—	661	—	—	625	—
Diluted EPS:						
Earnings available to common shareholders	$492,141	509,242	$ 0.97	$457,795	509,566	$ 0.90

	Nine Months Ended Sept. 30, 2017			Nine Months Ended Sept. 30, 2016		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$958,674	—	—	$895,902	—	—
Basic EPS:						
Earnings available to common shareholders	958,674	508,468	$ 1.89	895,902	508,840	$ 1.76
Effect of dilutive securities:						
Time based equity awards	—	584	—	—	556	—
Diluted EPS:						
Earnings available to common shareholders	$958,674	509,052	$ 1.88	$895,902	509,396	$ 1.76

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2017	2016	2017	2016
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$23,547	$22,940	$465	$432
Interest cost	36,702	40,027	5,984	6,527
Expected return on plan assets	(52,318)	(52,575)	(6,155)	(6,249)
Amortization of prior service credit	(442)	(478)	(2,672)	(2,672)
Amortization of net loss	26,671	24,384	1,672	1,011

Net periodic benefit cost (credit)	34,160	34,298	(706)	(951)
Costs not recognized due to the effects of regulation	(3,610)	(3,976)	—	—
Net benefit cost (credit) recognized for financial reporting	$30,550	$30,322	$(706)	$(951)

Table of Contents

	Nine Months Ended Sept. 30			
	2017	2016	2017	2016
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$70,641	$68,805	$1,395	$1,295
Interest cost	110,106	120,078	17,952	19,580
Expected return on plan assets	(156,953)	(157,725)	(18,466)	(18,746)
Amortization of prior service credit	(1,326)	(1,439)	(8,015)	(8,015)
Amortization of net loss	80,012	73,154	5,016	3,031
Net periodic benefit cost (credit)	102,480	102,873	(2,118)	(2,855)
Costs not recognized due to the effects of regulation	(11,523)	(12,587)	—	—
Net benefit cost (credit) recognized for financial reporting	$90,957	$90,286	$(2,118)	$(2,855)

In January 2017, contributions of $150.0 million were made across four of Xcel Energy’s pension plans. Xcel Energy does not expect additional pension contributions during 2017.

13. Other Comprehensive Income (Loss)

Changes in accumulated other comprehensive (loss) income, net of tax, for the three and nine months ended Sept. 30, 2017 and 2016 were as follows:

	Three Months Ended Sept. 30, 2017			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at June 30	$(49,497)	$ 111	$ (57,409)	$(106,795)
Other comprehensive income before reclassifications	23	—	—	23
Losses reclassified from net accumulated other comprehensive loss	981	—	982	1,963
Net current period other comprehensive income	1,004	—	982	1,986
Accumulated other comprehensive (loss) income at Sept. 30	$(48,493)	$ 111	$ (56,427)	$(104,809)

	Three Months Ended Sept. 30, 2016			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at June 30	$(52,980)	$ 110	$ (53,925)	$(106,795)
Other comprehensive loss before reclassifications	(4)	—	—	(4)
Losses reclassified from net accumulated other comprehensive loss	960	—	878	1,838
Net current period other comprehensive income	956	—	878	1,834
Accumulated other comprehensive (loss) income at Sept. 30	$(52,024)	$ 110	$ (53,047)	$(104,961)

	Nine Months Ended Sept. 30, 2017			
(Thousands of Dollars)	Gains and Losses on Cash Flow	Unrealized Gains on Marketable Securities	Defined Benefit Pension and	Total

	Hedges		Postretirement Items	
Accumulated other comprehensive (loss) income at Jan. 1	$(51,151)	$ 110	$ (59,313)	$(110,354)
Other comprehensive income before reclassifications	49	1	—	50
Losses reclassified from net accumulated other comprehensive loss	2,609	—	2,886	5,495
Net current period other comprehensive income	2,658	1	2,886	5,545
Accumulated other comprehensive (loss) income at Sept. 30	$(48,493)	$ 111	$ (56,427)	$(104,809)

Table of Contents

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2016 Gains and Losses on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(54,862)	$ 110	$ (55,001)	$(109,753)
Other comprehensive income (loss) before reclassifications	4	—	(653)	(649)
Losses reclassified from net accumulated other comprehensive loss	2,834	—	2,607	5,441
Net current period other comprehensive income	2,838	—	1,954	4,792
Accumulated other comprehensive (loss) income at Sept. 30	$(52,024)	$ 110	$ (53,047)	$(104,961)

Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2017 and 2016 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Three Months Ended Sept. 30, 2017	Three Months Ended Sept. 30, 2016
Losses (gains) on cash flow hedges:		
Interest rate derivatives	$ 1,579 (a)	$ 1,502 (a)
Vehicle fuel derivatives	(11) (b)	46 (b)
Total, pre-tax	1,568	1,548
Tax benefit	(587)	(588)
Total, net of tax	981	960
Defined benefit pension and postretirement losses:		
Amortization of net loss	1,622 (c)	1,478 (c)
Prior service credit	(58) (c)	(64) (c)
Total, pre-tax	1,564	1,414
Tax benefit	(582)	(536)
Total, net of tax	982	878
Total amounts reclassified, net of tax	$ 1,963	$ 1,838

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Nine Months Ended Sept. 30, 2017	Nine Months Ended Sept. 30, 2016
Losses (gains) on cash flow hedges:		

Interest rate derivatives	$ 4,257 [a]	$ 4,470 [a]
Vehicle fuel derivatives	(16) [b]	150 [b]
Total, pre-tax	4,241	4,620
Tax benefit	(1,632)	(1,786)
Total, net of tax	2,609	2,834
Defined benefit pension and postretirement losses:		
Amortization of net loss	4,868 [c]	4,434 [c]
Prior service credit	(177) [c]	(192) [c]
Total, pre-tax	4,691	4,242
Tax benefit	(1,805)	(1,635)
Total, net of tax	2,886	2,607
Total amounts reclassified, net of tax	$ 5,495	$ 5,441

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 12 for details regarding these benefit plans.

36

Table of Contents

Item 2 — MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy’s financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying unaudited consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy’s operating results, quarterly financial results are not an appropriate base from which to project annual results.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2017 and 2018 earnings per share guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “po and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other securities filings (including Xcel Energy’s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2016, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) to obtain financing on favorable terms; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

Financial Review

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of Xcel Energy’s core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Table of Contents

Results of Operations

The following table summarizes diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2017	2016	2017	2016
NSP-Minnesota	$0.45	$0.41	$0.81	$0.74
PSCo	0.37	0.34	0.78	0.74
SPS	0.13	0.13	0.25	0.24
NSP-Wisconsin	0.04	0.05	0.12	0.11
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.04
Regulated utility [(a)]	1.00	0.94	1.98	1.87
Xcel Energy Inc. and other	(0.03)	(0.04)	(0.10)	(0.11)
GAAP diluted EPS	$0.97	$0.90	$1.88	$1.76

(a) Amounts may not add due to rounding.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings for certain items. Xcel Energy’s management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy’s fundamental core earnings power. Xcel Energy’s management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

Summary of Earnings

Xcel Energy — Xcel Energy’s earnings increased $0.07 per share for the third quarter of 2017 and $0.12 per share year-to-date. Earnings for the third quarter of 2017 increased due to higher electric margins to recover infrastructure investments, along with a lower ETR and lower O&M expenses, partially offset by higher depreciation expense and property taxes.

NSP-Minnesota — Earnings increased $0.04 per share for the third quarter of 2017 and $0.07 per share year-to-date. The year-to-date increase in earnings reflects electric rate increases, lower ETR and reduced O&M expenses. The decrease in the ETR is largely driven by resolution of IRS appeals/audits and an increase in research and experimentation credits. The lower O&M expenses primarily relate to the timing of maintenance activities and the overhauls at various generation facilities and reduced expense for nuclear refueling outages. These positive factors were partially offset by depreciation expense (for additional capital investments, including the Courtenay Wind Farm, and prior year amortization of Minnesota’s excess depreciation reserve) and higher property taxes.

PSCo — Earnings increased $0.03 per share for the third quarter of 2017 and $0.04 per share year-to-date. The year-to-date increase in earnings, driven by higher electric margins, lower O&M expenses and lower ETR, were partially offset by increased depreciation expense associated with electric and natural gas investments. The lower O&M expenses are driven by the timing of maintenance and overhauls at various generation facilities and the impact of costs associated with storm damage in 2016.

SPS — Earnings were flat for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date increase in electric margin was attributable to rate increases in Texas and New Mexico, partially offset by the impact of unfavorable weather. This increase was largely offset by higher depreciation expense for transmission and distribution investments and timing of O&M expenses, including the prior year deferrals associated with the Texas 2016 rate case.

NSP-Wisconsin — Earnings decreased $0.01 per share for the third quarter of 2017 and increased $0.01 per share year-to-date. The year-to-date change was driven by increases in electric and natural gas rates, partially offset by depreciation expense primarily related to transmission and distribution investments and the impact of unfavorable weather.

Table of Contents

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2017 EPS compared with the same period in 2016:

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2016 GAAP diluted EPS	$ 0.90	$ 1.76
Components of change — 2017 vs. 2016		
Higher electric margins	0.02	0.14
Lower ETR [(a)]	0.07	0.10
Lower O&M expenses	0.06	0.07
Higher natural gas margins	—	0.01
Higher depreciation and amortization	(0.05)	(0.16)
Higher conservation and DSM expenses (offset by higher revenues)	(0.01)	(0.03)
Other, net	(0.02)	(0.01)
2017 GAAP diluted EPS	$ 0.97	$ 1.88

(a) Lower ETR includes the impact of an additional $9.6 million and $18.4 million of wind production tax credits (PTCs) for the three and nine months ended Sept. 30, 2017, respectively, which are largely flowed back to customers through electric margin.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity historically used per degree of temperature. Weather deviations from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales.

The percentage increase (decrease) in normal and actual HDD, CDD and THI is provided in the following table:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
HDD	(16.5)%	(52.6)%	67.5 %	(13.6)%	(12.7)%	(2.2)%
CDD	5.3	11.0	(4.5)	5.9	8.3	(1.8)
THI	(11.6)	6.5	(17.5)	(10.6)	8.6	(18.5)

39

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with normal weather conditions:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016
Retail electric	$(0.011)	$0.024	$(0.035)	$(0.032)	$0.020	$(0.052)
Firm natural gas	—	(0.001)	0.001	(0.020)	(0.014)	(0.006)
Total (excluding decoupling)	$(0.011)	$0.023	$(0.034)	$(0.052)	$0.006	$(0.058)
Decoupling – Minnesota	0.015	(0.008)	0.023	0.023	(0.009)	0.032
Total (adjusted for recovery from decoupling)	$0.004	$0.015	$(0.011)	$(0.029)	$(0.003)	$(0.026)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2017 compared to the same period in 2016:

	Three Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	(6.8)%	(2.5)%	(7.4)%	(6.9)%	(5.3)%
Electric commercial and industrial	(2.7)	0.8	(1.0)	1.5	(0.9)
Total retail electric sales	(3.9)	(0.3)	(2.5)	(0.8)	(2.2)
Firm natural gas sales	8.5	4.7	N/A	11.4	6.2

	Three Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	(1.5)%	(3.0)%	(2.0)%	(0.4)%	(2.1)%
Electric commercial and industrial	(1.9)	0.7	0.3	3.0	(0.2)
Total retail electric sales	(1.8)	(0.6)	(0.3)	2.0	(0.8)
Firm natural gas sales	6.9	(0.6)	N/A	9.6	2.1

	Nine Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	(3.3)%	(1.9)%	(4.4)%	(2.7)%	(2.9)%
Electric commercial and industrial	(1.6)	0.6	0.7	1.5	(0.2)
Total retail electric sales	(2.1)	(0.2)	(0.4)	0.3	(1.0)
Firm natural gas sales	4.4	(5.5)	N/A	4.5	(1.9)

	Nine Months Ended Sept. 30				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	(0.5)%	(1.5)%	(1.7)%	0.4%	(1.0)%
Electric commercial and industrial	(1.0)	0.7	1.0	2.1	0.2
Total retail electric sales	(0.9)	—	0.3	1.6	(0.2)
Firm natural gas sales	4.4	(1.0)	N/A	4.0	1.0

Table of Contents

	Nine Months Ended Sept. 30 (Excluding Leap Day) [b]				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	(0.2)%	(1.2)%	(1.3)%	0.8 %	(0.6)%
Electric commercial and industrial	(0.7)	1.0	1.3	2.4	0.6
Total retail electric sales	(0.5)	0.3	0.7	1.9	0.2
Firm natural gas sales	5.3	(0.3)	N/A	4.8	1.8

(a) Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 30-40 basis points for retail electric and 70-80 basis points for firm natural gas for the nine months ended.

Weather-normalized Electric Sales Growth (Decline) — Year-To-Date Excluding Leap Day

- NSP-Minnesota’s residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in commercial and industrial (C&I) sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services offset increased sales to large customers in manufacturing and energy industries.
- PSCo’s decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, which were partially reduced by lower use for the small C&I class.
- SPS’ residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use per customer driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin’s residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and an increase in sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized Natural Gas Sales Growth (Decline) — Year-To-Date Excluding Leap Day

- Across most service territories, higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. The following table details the electric revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2017	2016	2017	2016
Electric revenues	$2,784	$2,800	$7,421	$7,209
Electric fuel and purchased power	(1,006)	(1,037)	(2,850)	(2,755)
Electric margin	$1,778	$1,763	$4,571	$4,454

41

Table of Contents

The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2017 vs. 2016	Nine Months Ended Sept. 30 2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	$ 25	$ 102
Trading	8	50
Non-fuel riders	19	39
Higher conservation and DSM revenues (offset by higher expenses)	10	24
Decoupling (weather portion - Minnesota)	17	24
Fuel and purchased power cost recovery	(55)	1
Wholesale transmission revenue	(12)	—
Estimated impact of weather	(26)	(39)
Conservation incentive	(8)	(12)
Other, net	6	23
Total (decrease) increase in electric revenues	$ (16)	$ 212

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2017 vs. 2016	Nine Months Ended Sept. 30 2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	$ 25	$ 102
Non-fuel riders	19	39
Higher conservation and DSM revenues (offset by higher expenses)	10	24
Decoupling (weather portion - Minnesota)	17	24
Estimated impact of weather	(26)	(39)
Wholesale transmission revenue, net of costs	(24)	(37)
Conservation incentive	(8)	(12)
Other, net	2	16
Total increase in electric margin	$ 15	$ 117

Natural Gas Revenues and Margin

Total natural gas expense varies with changing sales and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to natural gas cost recovery mechanisms. The following table details natural gas revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2017	2016	2017	2016

Natural gas revenues	$214	$222	$1,130	$1,047
Cost of natural gas sold and transported	(64)	(68)	(543)	(470)
Natural gas margin	$150	$154	$587	$577

The following tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2017 vs. 2016	Nine Months Ended Sept. 30 2017 vs. 2016
Purchased natural gas adjustment clause recovery	$ (4)	$ 72
Infrastructure and integrity riders	(1)	11
Estimated impact of weather	1	(4)
Other, net	(4)	4
Total (decrease) increase in natural gas revenues	$ (8)	$ 83

42

Table of Contents

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2017 vs. 2016	Nine Months Ended Sept. 30 2017 vs. 2016
Infrastructure and integrity riders	$ (1)	$ 11
Estimated impact of weather	1	(4)
Other, net	(4)	3
Total (decrease) increase in natural gas margin	$ (4)	$ 10

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $48.5 million, or 8.2 percent, for the third quarter of 2017 and $58.3 million, or 3.3 percent, year-to-date. The significant changes are summarized in the table below:

(Millions of Dollars)	Three Months Ended Sept. 30 2017 vs. 2016	Nine Months Ended Sept. 30 2017 vs. 2016
Plant generation costs	$ (4.5)	$ (33.9)
Nuclear plant operations and amortization	(11.0)	(17.3)
Electric distribution costs	(16.0)	(10.7)
Transmission costs	(3.1)	(9.9)
Employee benefits expense	(7.0)	9.7
Texas 2016 electric rate case cost deferral	—	7.9
Other, net	(6.9)	(4.1)
Total decrease in O&M expenses	$ (48.5)	$ (58.3)

- Plant generation costs decreased primarily due to the timing of planned maintenance and overhauls at a number of generation facilities;
- Nuclear plant operations and amortization expenses are lower mostly due to savings initiatives and reduced refueling outage costs;
- Electric distribution costs declined as a result of storm damage expense incurred in 2016; and
- Transmission costs decreased mostly due to the timing of transmission line maintenance.

Conservation and DSM Expenses — Conservation and DSM expenses increased $9.8 million, or 15.4 percent, for the third quarter of 2017 and $28.9 million, or 16.3 percent, year-to-date. The increase was due to higher recovery rates and additional customer participation in electric conservation programs, mostly in Minnesota. Conservation and DSM expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization increased $42.6 million, or 13.0 percent, for the third quarter of 2017 and $131.0 million, or 13.5 percent, year-to-date. The increase was primarily due to capital investments, including the Courtenay Wind Farm, a new enterprise resource planning system and prior year amortization of the excess depreciation reserve in Minnesota.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $16.4 million, or 14.0 percent for the third quarter of 2017 and $9.6 million, or 2.4 percent year-to-date. The increase was primarily due to higher property taxes in Minnesota.

AFUDC, Equity and Debt — Allowance for funds used during construction (AFUDC) increased $9.5 million for the third quarter of 2017 and $14.3 million year-to-date. The increase was primarily due to higher construction work in progress, particularly the Rush Creek wind project.

Interest Charges — Interest charges increased $1.9 million, or 1.2 percent, for the third quarter of 2017 and $12.7 million, or 2.6 percent, year-to-date. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Table of Contents

Income Taxes — Income tax expense decreased $33.6 million for the third quarter and $47.6 million for the first nine months of 2017, compared to the same periods in 2016. The decrease was primarily due to net tax benefits related to an increase in wind PTCs, the resolution of past appeals/audits, and an increase in research and experimentation credits. The ETR was 29.4 percent for the third quarter of 2017 compared with 34.2 percent for the same period in 2016 and 30.7 percent for the first nine months of 2017, compared to 34.5 percent for the first nine months of 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above.

Public Utility Regulation

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 1 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2016 and Public Utility Regulation included in Item 2 of Xcel Energy Inc.'s
Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Xcel Energy Inc.

Wind Development — Xcel Energy plans to significantly expand its wind capacity at NSP-Minnesota, PSCo and SPS. The CPUC approved the Rush Creek wind project in 2016. In July 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation, including ownership of 1,150 MW of wind generation by NSP-Minnesota.

The PUCT and NMPRC are expected to rule on SPS' wind projects by the end of the first quarter of 2018. Hearings in Texas with the PUCT are scheduled for Nov. 6 through Nov. 17, 2017. Hearings in New Mexico with the NMPRC are scheduled for Nov. 28 through Dec. 1, 2017.

In September 2017, NSP-Minnesota filed with the MPUC seeking approval to build and own the Dakota Range project, a 300 MW wind project in South Dakota. The project is projected to be placed into service by the end of 2021 to qualify for 80 percent of the PTC. NSP-Minnesota has requested that the MPUC approve the proposed wind project by March 2018.

These wind projects (with the exception of the Dakota Range project) would qualify for 100 percent of the PTC and are expected to provide billions of dollars of savings to Xcel Energy's customers and substantial environmental benefits. Projected savings/benefits assume fuel costs and generation mix consistent with various commission approved resource plans.

The following table details these wind projects:

Project Name	Capacity (MW)	State	Estimated Year of Completion	Ownership/PPA	Regulatory Status
Rush Creek	600	CO	2018	PSCo	Approved by CPUC
Freeborn	200	MN/IA	2020	NSP-Minnesota	Approved by MPUC
Blazing Star 1	200	MN	2019	NSP-Minnesota	Approved by MPUC
Blazing Star 2	200	MN	2020	NSP-Minnesota	Approved by MPUC
Lake Benton	100	MN	2019	NSP-Minnesota	Approved by MPUC
Foxtail	150	ND	2019	NSP-Minnesota	Approved by MPUC
Crowned Ridge	300	SD	2019	NSP-Minnesota	Approved by MPUC
Dakota Range	300	SD	2021	NSP-Minnesota	Pending MPUC Approval

Hale	478	TX	2019	SPS	Pending PUCT & NMPRC Approval
Sagamore	522	NM	2020	SPS	Pending PUCT & NMPRC Approval
Total Ownership	3,050				
Crowned Ridge	300	SD	2019	PPA	Approved by MPUC
Clean Energy 1	100	ND	2019	PPA	Approved by MPUC
Bonita	230	TX	2019	PPA	Pending PUCT & NMPRC Approval
Total PPA	630				
Total Wind Capacity	3,680				

Table of Contents

NSP-Minnesota

PPA Terminations and Amendments — In June and July 2017, NSP-Minnesota filed requests with the MPUC and/or the NDPSC for several initiatives including changes to four PPAs to reduce future costs for customers. These actions include the following:

- The termination of a PPA with Benson Power LLC (Benson) for its 55 MW biomass facility in Benson, Minn., including the purchase and closure of the facility. The purchase of the Benson biomass facility requires FERC approval, which was requested in August 2017. The transaction would result in payments of $95 million to terminate the PPA and acquire the facility, as well as additional expenditures of approximately $26 million to temporarily operate then close the facility.
- The termination of a PPA with Laurentian Energy Authority I, LLC (Laurentian) for its 35 MW of biomass facilities in Hibbing and Virginia, Minn. The termination of the Laurentian PPA would result in $108.5 million of contract cancellation payments over six years.
- The remaining two requested PPA changes involve a PPA extension for a 34 MW waste-to-energy facility at a price reflective of current market conditions and termination of another 12 MW waste-to-energy PPA.

NSP-Minnesota has requested recovery of all costs associated with these changes through the Fuel Clause Adjustment (FCA), including a return on NSP-Minnesota's total investment in the Benson transaction over the remaining life of the current PPA through 2028. NSP-Minnesota and NSP-Wisconsin will jointly request FERC approval to modify the Interchange Agreement to share a portion of the cost with NSP-Wisconsin. If approved, these actions together are intended to provide approximately $653 million in net cost savings to NSP System customers over the next 10 years.

Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. The annual costs for a legal separation and pseudo-separation are estimated to be approximately $3 million and $1 million, respectively. A one-time cost of approximately $10 million would also be incurred to establish a North Dakota operating company under legal separation. Costs are not expected to be incurred until 2020 and are anticipated to be recoverable through rates. The filing proposed a procedural schedule that considers an order in mid-2018. In October 2017, NDPSC staff filed testimony recommending no change to the current system of proxy pricing and policy-based disallowances claiming there is a likelihood of overall increased costs and potential loss of resource diversity. NSP-Minnesota's rebuttal testimony is due Nov. 15, 2017 and hearings are scheduled in January 2018.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below was approximately $2 billion. NSP-Minnesota and NSP-Wisconsin were responsible for approximately $1.04 billion of the total investment and the majority of this investment has occurred. The projects are as follows:

- Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 161/345 kilovolt (KV) transmission lines — The final 161 KV and 345 KV segments of the project went into service in January 2016 and September 2016, respectively;
- Brookings County, S.D. to Hampton, Minn. 345 KV transmission line — The project was placed in service in March 2015;
- Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line — The project was placed in service in September 2012;

- Monticello, Minn. to Fargo, N.D. 345 KV transmission line — The final portion of the project was placed in service in April 2015; and
- Big Stone South to Brookings County, S.D. 345 KV transmission line — The project was placed in service in September 2017.

Minnesota FCA — In October 2017, the MPUC voted to change the process in which utilities seek fuel cost recovery under the FCA in Minnesota. Each month, utilities collect amounts equal to the baseline cost of energy set at the start of the plan year, as well as issue refunds or billings for the difference relative to the baseline costs. Under the new process, monthly variations to the baseline costs will be tracked and netted over a 12-month period. Subsequently, utilities can seek recovery of any overage. The MPUC has requested additional compliance filings from all utilities outlining the details and timing of the proposed process.

Table of Contents

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. NSP-Minnesota's next triennial nuclear decommissioning filing is expected to be submitted in the fourth quarter of 2017. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2016 for further discussion regarding the nuclear generating plants. The circumstances set forth in Nuclear Power Operations and Waste Disposal included in Item 1 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2016 and Nuclear Power Operations included in Item 2 of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

NSP-Wisconsin

2017 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the nine months ended Sept. 30, 2017 were lower than authorized in rates and outside the two percent annual tolerance band established in the Wisconsin fuel cost recovery rules, primarily due to lower sales volume and lower purchased power costs coupled with moderate weather and generation sales into the MISO market. Under the fuel cost recovery rules, NSP-Wisconsin may retain the amount of over-recovery up to two percent of authorized annual fuel costs, or approximately $3.7 million. However, NSP-Wisconsin must defer the amount of over-recovery in excess of the two percent annual tolerance band for future refund to customers. Accordingly, NSP-Wisconsin recorded a deferral of approximately $10.5 million through Sept. 30, 2017. The amount of the deferral could increase or decrease based on actual fuel costs incurred for the remainder of the year. In the first quarter of 2018, NSP-Wisconsin will file a reconciliation of 2017 fuel costs with the PSCW. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2018.

PSCo

Rush Creek Wind Ownership Proposal — In 2016, the CPUC granted PSCo a Certificate of Public Convenience and Necessity (CPCN) to build, own and operate a 600 MW wind generation facility in Colorado at Rush Creek. The CPCN includes a hard cost-cap of $1.096 billion (including transmission costs) and a capital cost sharing mechanism between customers and PSCo of 82.5 percent to customers and 17.5 percent to PSCo for every $10 million the project comes in below the cost-cap.

All major contracts required to complete the project have been executed including the Vestas turbine supply and balance of plant agreements. Vestas PTC components for safe harboring the facility have been fabricated and are currently being stored at Vestas facilities in Colorado. Construction of roads, collection systems, and foundations began in April 2017.

Colorado Energy Plan (CEP) — In May 2016, PSCo filed its 2016 Electric Resource Plan which included the estimated need for additional generation resources through 2024. In April 2017, the CPUC approved the modeling assumptions that will be used in the Request for Proposal (RFP) process. In August 2017, PSCo filed an updated capacity need with the CPUC of 450 MW.

In August 2017, PSCo, along with various other stakeholders, filed a stipulation agreement proposing the CEP. The major components include:

- Early retirement of 660 MW of coal-fired generation at Comanche Units 1 (2022) and 2 (2025);
-

- An RFP which could result in the addition of up to 1,000 MW of wind, 700 MW solar and 700 MW of natural gas and/or storage;
- Utility ownership targets of 50 percent renewable generation resources and 75 percent of natural gas-fired, storage, or renewable with storage generation resources;
- Accelerated depreciation for the early retirement of the two Comanche units and establishment of a regulatory asset to collect the incremental depreciation expense and related costs;
- Reduction of the Renewable Energy Standard Adjustment rider, from two percent to one percent, subject to regulatory proceedings, effective beginning 2021 or 2022; and
- Construction of a new transmission switching station to further the development of renewable generating resources.

In August 2017, PSCo issued an All-Source RFP. Bids are due on Nov. 28, 2017. PSCo anticipates filing its' recommended portfolios in April 2018. The CPUC is expected to rule on the stipulation agreement in March 2018. A CPUC decision on the recommended portfolio is anticipated in the summer of 2018.

Approval of the CEP could increase the total capital investment up to $1.5 billion. The CEP is not included in PSCo and Xcel Energy's base capital expenditures forecast. See Item 2. Management's Discussion and Analysis of Financial Condition and Result of Operations — Capital Requirements for further discussion of the capital forecast.

46

Table of Contents

Advanced Grid Intelligence and Security — In July 2017, the CPUC approved PSCo's CPCN for implementation of its advanced grid initiative. The project incorporates installing advanced meters, implementing hardware and software applications to allow the distribution system to operate at a lower voltage (integrated volt-var optimization) and installing communications infrastructure. These major projects are expected to improve customer experience, enhance grid reliability and enable the implementation of new and innovative programs and rate structures.

In June 2017, the CPUC approved a settlement, which delayed the advanced meter deployment from 2017-2021 to 2019-2024. The total capital cost of the project included in the CPCN is approximately $537 million for 2017-2024. As a result of the settlement, approximately $120 million of capital investment was deferred to 2022-2024.

Decoupling Filing — In July 2016, PSCo filed a request with the CPUC to approve a partial decoupling mechanism, which would adjust annual revenues based on changes in weather normalized average use per customer for the residential and small commercial classes.

In July 2017, the CPUC issued a decision which approved the following key decisions regarding decoupling:

- Effective Jan. 1, 2018 through December 2023 (subject to establishing new rates in the next electric rate case);
- Applicable to the residential class and small commercial class;
- Based on total class revenues (subject to establishing the base period in the next electric rate case);
- Based on actual sales; and
- Subject to a soft cap of 3 percent on any annual adjustment.

In August 2017, the CPUC denied PSCo's request for reconsideration of the order.

Boulder, Colo. Municipalization — In 2011, in the City of Boulder, Colo. (Boulder), voters passed a ballot measure authorizing the formation of a municipal utility, subject to certain conditions. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility. In 2016, the Colorado Court of Appeals preserved PSCo's ability to do so. Subsequently, Boulder filed a Petition for Writ of Certiorari with the Colorado Supreme Court. In August 2017, the Colorado Supreme Court granted the petition to review the Colorado Court of Appeals decision.

In 2015, the Boulder District Court affirmed a prior CPUC decision that Boulder cannot serve customers outside its city limits. The District Court also ruled the CPUC has jurisdiction over the transfer of any facilities to Boulder and in determining how the systems are separated to preserve reliability, safety and effectiveness. Further, the Boulder District Court dismissed the condemnation action Boulder had filed, finding that the CPUC must give approval before Boulder files any future condemnation proceeding. Boulder does not have authorization to initiate a condemnation proceeding at this time.
Beginning in 2015, Boulder filed multiple separation applications, the most recent one being in May 2017. In June 2017, PSCo and other intervenors filed alternatives to Boulder's separation plan and opposed certain sharing; contracting and financing aspects of the plan.

In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position, stating PSCo is not required to:

- Finance Boulder's municipalization efforts;
- Design or construct future Boulder electric distribution facilities;
- Enter into joint use of pole arrangements with Boulder; and

- Use a third party to design and build facilities.

The CPUC provided conditional approval related to the transfer of some of the electrical distribution assets in Boulder, however subject to completion of certain items, including:

- Filing an agreement between Boulder and PSCo providing permanent rights for PSCo to place and access facilities in Boulder needed to continue to serve its customers;
- Filing a complete and accurate revised list of distribution assets to be transferred; and
- Filing an agreement to address numerous aspects of payments from Boulder to PSCo for costs of Boulder's municipalization efforts.

Table of Contents

The CPUC requested those filings be made by Dec. 13, 2017. The CPUC has established a process whereby once those filings are made, additional hearings may be held.

At the end of 2017, several Boulder measures expire absent voter approvals, including the Utility Occupational Tax (UOT) which funds Boulder's municipalization efforts. In response, Boulder has placed the following measures on the November 2017 ballot:

- An extension and increase of the UOT for funding Boulder's exploration of municipalization;
- Requiring final voter approval prior to Boulder issuing debt to acquire assets and fund the start up of a local electric utility; and
- Extending Boulder city council's authority to hold non-public, executive sessions to discuss legal strategy related to municipalization, but not to discuss certain settlement options with PSCo.

Mountain West Transmission Group (MWTG) — PSCo, along with six other transmission owners from the Rocky Mountain region, have been considering creating and operating a joint transmission tariff to increase wholesale market efficiency and improve regional transmission planning. In September 2017, the MWTG determined that membership in the SPP RTO would provide opportunities to reduce customer costs, and maximize resource and electric grid utilization. If participation with SPP proceeds, the MWTG utilities expect an economic benefit. In October 2017, the MWTG commenced negotiations with SPP through the SPP public stakeholder process.

SPP's organizational group will address respective findings, objectives and next steps related to MWTG's consideration of SPP membership. Should the MWTG decide to move forward, SPP would make filings with the FERC and PSCo would make filings with the CPUC and the FERC, in mid-2018. If approved, MWTG operations within the SPP RTO would not be expected to begin until late 2019, at the earliest.

SPS

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In March 2016, the PUCT approved SPS' Certificate of Convenience and Necessity (CCN) for the 27-mile Yoakum County to Texas/New Mexico State line portion of this 345 KV line project. A CCN for the 106-mile TUCO to Yoakum County substation segment was approved by the PUCT in September 2017 and is scheduled to be in service in the second quarter of 2020. A 36-mile CCN for the Texas/New Mexico state line to Hobbs Plant segment was filed in June 2017. Assuming approval of this CCN, the Yoakum County to Hobbs Plant segment is scheduled to be in service in summer of 2019. The estimated project cost for all three segments is approximately $239 million.

The TUCO Substation to Yoakum County Substation to Hobbs Plant Substation transmission line is part of a larger project which includes a 345 KV transmission line from the Hobbs Plant to the China Draw Substation. The Hobbs Plant to China Draw Substation portion of this project was approved by the NMPRC in November 2016 and has an estimated cost of $163 million. The total investment for the two transmission lines is approximately $402 million. The Hobbs Plant to China Draw Substation transmission line is under construction and is anticipated to be in service by June 1, 2018.

Wholesale Customer Participation in Electric Reliability Council of Texas (ERCOT) — In March 2016, the PUCT Staff requested comments on Lubbock Power & Light's (LP&L's) proposal to transition a portion of its load (approximately 430 MW on a peak basis) to the ERCOT in June 2019. LP&L's proposal would result in an approximate seven percent reduction of load in SPS, or a loss of approximately $18 million in wholesale transmission revenue. The remaining portion of LP&L's load (approximately 170 MW) would continue to be served by SPS. Should LP&L join ERCOT, costs to SPS' remaining customers would increase as SPS' transmission costs would be spread across a smaller base of customers.

The PUCT has indicated there will be a two-step process regarding LP&L’s possible transfer to ERCOT. The first step will be a proceeding to determine whether the proposed transfer is in the public interest and to consider certain protections for non-LP&L customers who would be affected by LP&L’s transfer. If the PUCT determines the transfer is in the public interest, the second step will be for LP&L to file a CCN application for transmission facilities to connect with ERCOT. The PUCT asked SPP and ERCOT to perform reliability and economic studies to better understand the implications of LP&L’s proposal. SPP and ERCOT filed the studies on June 30, 2017. In September 2017, LP&L filed its application with the PUCT for a public interest determination and proposed a transition date no later than June 2021. The PUCT issued a preliminary order setting out issues for the parties to address. A hearing on the matter is expected to be held in the first quarter of 2018 and a PUCT decision is expected in the second quarter of 2018.

No final decision regarding LP&L’s departure or its potential timing is expected until completion of the PUCT proceedings.

Table of Contents

Summary of Recent Federal Regulatory Developments

FERC

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries and transmission-only subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2016 and Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC ROE Policy — In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including two ROE complaints involving the MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. In April 2017, the D.C. Circuit vacated and remanded the June 2014 ROE order. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for the NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. The FERC has yet to act on the D.C. Circuit's decision. See Note 5 to the consolidated financial statements for discussion of the D.C. Circuit's decision and the impact on the MISO ROE Complaints.

Department of Energy (DOE) Grid Resiliency Notice of Proposed Rule (NOPR) — In September 2017, the DOE requested the FERC consider and adopt a Grid Resiliency and Pricing Rule to address threats to the U.S. electrical grid. The proposed DOE rule expands upon an August 2017 DOE grid study on the resiliency of the grid. Under the proposed rule, coal and nuclear generation facilities would qualify for full recovery of their costs, which includes a fair rate of return, if they meet the following criteria:

- Are located within a FERC-approved organized wholesale market operated by an RTO or Independent System Operator;
- Have 90 days of on-site fuel storage;
- Provide essential energy and ancillary reliability services to the grid;
- Are in compliance with all environmental mandates; and
- Are not subject to cost-of-service regulation by any state or local authority.

If implemented as written, the coal and nuclear generation owned by NSP-Minnesota, NSP-Wisconsin and SPS are not expected to be eligible for wholesale cost recovery from MISO or SPP because the generation is subject to state cost-of-service regulation. This rule could impact utilities in MISO or SPP subject to cost-of-service regulation if they have to compensate other generation facilities who qualify for full recovery of their costs under the rule. Xcel Energy is evaluating the DOE proposal and plans to engage in the FERC stakeholder process. The FERC has indicated that they plan to take action within 60 days, as requested by the DOE. It is unclear how the FERC will respond to the DOE's NOPR.

Minnesota State Right-Of-First Refusal (ROFR) Statute Complaint — In September 2017, LSP Transmission Holdings, LLC filed a complaint in the U.S. District Court in Minnesota against the Minnesota Attorney General, the MPUC and the DOC. The complaint was in response to NSP-Minnesota and ITC Midwest, LLC being assigned by MISO to jointly own a new 345 kilovolt transmission line that is planned to run from NSP-Minnesota's Wilmarth Substation near Mankato, Minn. to ITC Midwest's Huntley Substation in Minnesota south of Winnebago, Minn. The line is estimated to cost $108 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenges the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies are expected to answer the complaint in November 2017. NSP-Minnesota expects to intervene in the case. The timing and outcome of the litigation is uncertain.

49

Table of Contents

North American Electric Reliability Corporation (NERC) Supply Chain Standards — In September 2017, NERC filed supply chain cyber security reliability standards with the FERC. These standards consider the FERC’s directives to address supply chain cyber security risk management for industrial control system hardware, software, computing and network services associated with electric grid operations. The proposed reliability standards focus on security objectives including software integrity and authenticity, vendor remote access protections, information system planning and vendor risk management. It is uncertain when the FERC will take action to approve or remand the proposed reliability standards. If approved by the FERC, the proposed reliability standards will become effective on the first calendar quarter that is 18 months after the effective date of the approval. Xcel Energy is in the process of developing plans in accordance with the requirements of the standards. The additional cost for compliance is anticipated to be recoverable through wholesale and retail rates.

Public Utility Regulatory Policies Act (PURPA) Enforcement Complaint Against CPUC — In December 2016, Sustainable Power Group, LLC (sPower) petitioned the FERC to initiate an enforcement action in federal court against the CPUC under PURPA. The petition asserts that a December 2016 CPUC ruling, which indicated that a qualifying facility must be a successful bidder in a PSCo resource acquisition bidding process, violated PURPA and FERC rules. In January 2017, PSCo filed a motion to intervene and protest, arguing that the FERC should decline the petition. The CPUC filed a similar pleading. sPower has proposed to construct 800 MW of solar generation and 700 MW of wind generation in Colorado and seeks to require PSCo to contract for these resources under PURPA. If sPower were to prevail, PSCo’s ability to select generation resources through competitive bidding would be negatively affected. However, due to a lack of quorum at the FERC, the FERC did not act on that petition within the sixty days contemplated by PURPA. Subsequently sPower filed a complaint for declaratory and injunctive relief in the United States District Court for the District of Colorado (District Court) requesting that the court find the bidding requirement in the CPUC qualifying facility rules to be unlawful. PSCo intervened in that proceeding and the CPUC filed a motion to dismiss. In June 2017, the United States Magistrate Judge (Magistrate) issued a recommendation to the District Court that sPower’s complaint be dismissed because sPower failed to establish that it faced a substantial risk of harm. In October 2017, the District Court denied the CPUC’s motion to dismiss and instead allowed sPower to file an amended complaint. The case effectively starts over and PSCo is expected to intervene in the proceeding again. The timing of a resolution in this case is unclear.

Solar Gardens Investment

In July 2017, a newly formed subsidiary of Xcel Energy signed an agreement with a solar developer to construct and operate approximately 19 MW of new community solar gardens in Minnesota serving existing NSP-Minnesota customers. The projects are expected to achieve commercial operations in 2017 and 2018.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Table of Contents

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

At Sept. 30, 2017, the fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 2,465	$ 3,898	$ 3,712	$ —	$ 10,075
PSCo	1	107	105	—	—	212
PSCo	2	2	—	—	—	2
		$ 2,574	$ 4,003	$ 3,712	$ —	$ 10,289

	Options					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ (365)	$ (15)	$ —	$ —	$ (380)
NSP-Minnesota	2	—	3,921	1,579	—	5,500
		$ (365)	$ 3,906	$ 1,579	$ —	$ 5,120

1 — Prices actively quoted or based on actively quoted prices.
2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2017	2016
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 9,771	$ 11,040
Contracts realized or settled during the period	(9,118)	(2,628)
Commodity trading contract additions and changes during the period	14,756	3,139
Fair value of commodity trading	$ 15,409	$ 11,551

net contract assets
outstanding at
Sept. 30

At Sept. 30, 2017, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.6 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.3 million. At Sept. 30, 2016, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.3 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.3 million.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Three Months Ended Sept. 30	VaR Limit	Average	High	Low
2017	$ 0.07	$ 3.00	$ 0.13	$ 0.63	$ 0.03
2016	0.10	3.00	0.18	0.38	0.05

51

Table of Contents

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 12 percent of its 2017 and approximately 59 percent of its 2018 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 31 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material.

Separately, NSP-Minnesota has enriched nuclear fuel materials in process with Westinghouse Electric Corporation (Westinghouse). Westinghouse filed for Chapter 11 bankruptcy protection in March 2017. NSP-Minnesota owns materials in Westinghouse's inventory and has contracts in place under which Westinghouse will provide certain services during an upcoming outage at PI. Westinghouse provided nuclear fuel assemblies for the upcoming PI outage under the current nuclear fuel fabrication contract. Westinghouse has indicated its intention to continue to perform under the arrangements. Based on Westinghouse's stated intent and the interim financing secured to fund its on-going operations, NSP-Minnesota does not expect the bankruptcy to materially impact NSP-Minnesota's operational or financial performance.

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Sept. 30, 2017 and 2016, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately \$5.6 million and \$4.2 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Sept. 30, 2017, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Sept. 30, 2017, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$18.3 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$1.7 million. At Sept. 30, 2016, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$11.7 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$15.9 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy’s credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 8 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Table of Contents

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 2017. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as other comprehensive income (OCI) or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2017.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 3.0 percent and 7.6 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2017.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited transparency in the auction process, fair value measurements for FTRs have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $63.0 million and $2.8 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2017.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were $5.5 million in Level 3 commodity derivative assets and no liabilities for options held at Sept. 30, 2017. There were $0.2 million of Level 3 derivative assets held as forwards at Sept. 30, 2017.

Liquidity and Capital Resources

Cash Flows

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2017	2016
Cash provided by operating activities	$2,367	$2,425

Net cash provided by operating activities decreased $58 million for the nine months ended Sept. 30, 2017 compared with the nine months ended Sept. 30, 2016. The decrease was primarily due to higher interest payments and pension contributions, lower income tax refunds received, and the timing of vendor payments, customer receipts, refunds, and recovery of certain electric and natural gas riders and incentives, partially offset by higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expenses).

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2017	2016
Cash used in investing activities	$(2,239)	$(2,206)

Net cash used in investing activities increased $33 million for the nine months ended Sept. 30, 2017 compared with the nine months ended Sept. 30, 2016. The increase was primarily attributable to higher capital expenditures related to the Rush Creek wind generation facility, partially offset by lower capital expenditures related to the Courtenay wind farm and fewer rabbi trust investments in 2017.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2017	2016
Cash (used in) provided by financing activities	$(45)	$ 49

Net cash used in financing activities was $45 million for the nine months ended Sept. 30, 2017 compared with net cash provided by financing activities of $49 million for the nine months ended Sept. 30, 2016. The change was primarily attributable to higher repayments of long-term debt and dividend payments, partially offset by increased net short and long-term debt proceeds.

Table of Contents

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Capital Expenditures — The estimated base capital expenditures for Xcel Energy for 2018 through 2022 are shown in the table below:

	Base Capital Forecast					
By Subsidiary (Millions of Dollars)	2018	2019	2020	2021	2022	2018 - 2022 Total
NSP-Minnesota	$1,370	$1,910	$1,450	$1,590	$1,500	$7,820
PSCo	1,650	1,020	950	1,150	1,410	6,180
SPS	1,020	1,140	710	470	540	3,880
NSP-Wisconsin	250	250	240	280	290	1,310
Other [(a)]	20	(90)	(90)	(30)	—	(190)
Total capital expenditures	$4,310	$4,230	$3,260	$3,460	$3,740	$19,000

	Base Capital Forecast					
By Function (Millions of Dollars)	2018	2019	2020	2021	2022	2018 - 2022 Total
Electric distribution	$750	$810	$870	$1,110	$1,380	$4,920
Renewables	1,410	1,860	880	270	—	4,420
Electric transmission	770	540	570	860	980	3,720
Electric generation	520	370	290	520	530	2,230
Natural gas	460	400	410	420	510	2,200
Other [(b)]	400	250	240	280	340	1,510
Total capital expenditures	$4,310	$4,230	$3,260	$3,460	$3,740	$19,000

[(a)] Other category includes intercompany transfers for safe harbor wind turbines.
[(b)] Amounts in other category are net of intercompany transfers.

The base capital expenditure forecast does not include the Colorado Energy Plan, which if approved could increase the total capital investment up to $1.5 billion.

Xcel Energy's capital expenditure forecast is subject to continuing review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve requirements, availability of purchased power, alternative plans for meeting long-term energy needs, environmental regulation, and merger, acquisition and divestiture opportunities.

Financing for Capital Expenditures through 2022 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. The current estimated financing plans of Xcel Energy for 2018 through 2022 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$13,920
New Debt**	4,695

Equity through the Dividend Reinvestment Program (DRIP) and Benefit Programs	385
Base Capital Expenditures 2018-2022	$19,000
Maturing Debt	$3,450

* Net of dividends and pension funding.
** Reflects a combination of short and long-term debt; net of refinancing.

54

Table of Contents

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and the SEC with expanded regulatory authority over derivative and swap transactions. The CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to $3 billion in 2018. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy's Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy is currently meeting all reporting requirements and transaction restrictions.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities, and alternative investments, including private equity, real estate, hedge fund of funds and commodity investments.

- In January 2017, contributions of $150.0 million were made across four of Xcel Energy's pension plans;
- In 2016, contributions of $125.2 million were made across four of Xcel Energy's pension plans; and
- For future years, contributions will be made as deemed appropriate based on evaluation of various factors including the funded status of the plans, minimum funding requirements, interest rates and expected investment returns.

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Sept. 30, 2017, approximately $100.9 million of cash was held in these accounts.

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.75 billion, and each credit facility terminates in June 2021.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving credit facility termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Oct. 24, 2017, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,000	$ 366	$ 634	$ 1	$ 635
PSCo	700	4	696	18	714
NSP-Minnesota	500	22	478	—	478

SPS	400	3	397	49	446
NSP-Wisconsin	150	119	31	1	32
Total	$ 2,750	$ 514	$ 2,236	$ 69	$ 2,305

(a) These credit facilities expire in June 2021.

(b) Includes outstanding commercial paper and letters of credit.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $1 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and
- $150 million for NSP-Wisconsin.

Table of Contents

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2017	Year Ended Dec. 31, 2016
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	514	392
Average amount outstanding	679	485
Maximum amount outstanding	867	1,183
Weighted average interest rate, computed on a daily basis	1.50 %	0.74 %
Weighted average interest rate at period end	1.53	0.95

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

Financing — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

During 2017, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing the following:

- PSCo issued $400 million of 3.80 percent first mortgage bonds due June 15, 2047;
- SPS issued $450 million of 3.70 percent first mortgage bonds due Aug. 15, 2047;
- NSP-Minnesota issued $600 million of 3.60 percent first mortgage bonds due Sept. 15, 2047;
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds in the fourth quarter; and
- Xcel Energy Inc. plans to issue short-term debt in the fourth quarter to meet financing needs.

Xcel Energy Inc. and its utility subsidiaries’ 2018 financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $750 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $300 million of first mortgage bonds;
- NSP-Wisconsin plans to issue approximately $150 million of first mortgage bonds;
- PSCo plans to issue approximately $700 million of first mortgage bonds; and
- SPS plans to issue approximately $300 million of first mortgage bonds.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors. Xcel Energy does not anticipate issuing any additional equity, beyond its DRIP and benefit programs, over the next five years based on its current base capital expenditure plan.

Debt Redemption

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- On Aug. 30, 2017, SPS reacquired $250 million of debt with a coupon rate of 8.75 percent and an original maturity date of Dec. 1, 2018. The redemption resulted in payment of an early redemption premium of $21.6 million which was deferred as a regulatory asset.
- On Sept. 29, 2017, NSP-Minnesota reacquired $500 million of debt with a coupon rate of 5.25 percent and an original maturity date of March 1, 2018. The redemption resulted in payment of an early redemption premium of $7.9 million which was deferred as a regulatory asset.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Table of Contents

Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy's narrowed 2017 GAAP and ongoing earnings guidance is $2.27 to $2.32 per share, compared with the previous issued guidance of $2.25 to $2.35 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2016 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent over 2016 levels.
- Capital rider revenue is projected to increase by $45 million to $55 million over 2016 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $180 million to $190 million over 2016 levels.
- Property taxes are projected to be within a range of approximately $0 million to $10 million over 2016 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $10 million to $20 million over 2016 levels.
- AFUDC — equity is projected to increase approximately $10 million to $20 million from 2016 levels.
- The ETR is projected to be approximately 31 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

Xcel Energy 2018 Earnings Guidance — Xcel Energy's 2018 GAAP and ongoing earnings guidance is $2.37 to $2.47 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent below 2017 levels.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2017 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $120 million to$130 million over 2017 levels.
- Property taxes are projected to increase approximately $35 million to $45 million over 2017 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $20 million to $30 million over 2017 levels.
- AFUDC — equity is projected to increase approximately $20 million to $30 million from 2017 levels.
- The ETR is projected to be approximately 30 percent to 32 percent.
- Average common stock and equivalents are projected to be approximately 510 million shares.

(a) Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5 percent to 6 percent off of a 2017 base of $2.30 per share (which represents the midpoint of the 2017 guidance range of $2.25 to $2.35 per share);
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and

- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management’s view, not reflective of ongoing operations.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management’s Discussion and Analysis — Derivatives, Risk Management and Market Risk under Item 2.

Table of Contents

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Sept. 30, 2017, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

In 2016, Xcel Energy implemented the general ledger modules, as well as initiated deployment of work management systems modules, of a new enterprise resource planning system to improve certain financial and related transaction processes. Xcel Energy is continuing to implement additional modules including the conversion of existing work management systems to this same system during 2017. In connection with this ongoing implementation, Xcel Energy is updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting systems. Xcel Energy does not believe that this implementation will have an adverse effect on its internal control over financial reporting.

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Part I Item 2 and Note 5 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.’s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2016, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

Table of Contents

Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 2017:

Period	Issuer Purchases of Equity Securities Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2017 — July 31, 2017	—	$ —	—	—
Aug. 1, 2017 — Aug. 31, 2017	—	—	—	—
Sept. 1, 2017 — Sept. 30, 2017	—	—	—	—
Total	—		—	—

Item 6 — EXHIBITS

* Indicates incorporation by reference
\+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 18, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Bylaws of Xcel Energy Inc., as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 18, 2016 (file no. 001-03034)).
4.01*	Supplemental Indenture No. 5 dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70 percent First Mortgage Bonds, Series No. 5 due 2047. (Exhibit 4.02 to Form 8-K of SPS dated Aug. 9, 2017 (file no. 001-03789)).
4.02*	Supplemental Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor trustee, creating $600 million principal amount of 3.60 percent First Mortgage Bonds, Series due Sept. 15, 2047. (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Sept. 13, 2017 (file no. 001-31387)).
10.1+	Fourth Amendment to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2017 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity,

(vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Oct. 27, 2017 By:/s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL
Robert C. Frenzel
Executive Vice President, Chief Financial Officer
(Principal Financial Officer)