HNI CORP
Form 8-K
February 10, 2010

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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of report (Date of earliest event reported): February 9, 2010

HNI Corporation
(Exact Name of Registrant as Specified in Charter)

Iowa	1-14225	42-0617510
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

408 East Second Street, P.O. Box 1109, Muscatine, Iowa 52761-0071
(Address of Principal Executive Offices, Including Zip Code)

Registrant's telephone number, including area code: (563) 272-7400

N/A
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instruction A.2.):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b)) o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 2 — Financial Information

Item 2.02 Results of Operations and Financial Condition.

On February 9, 2010, HNI Corporation (the "Corporation") issued a press release announcing its financial results for fourth quarter and year-end - fiscal 2009. A copy of the press release is attached hereto as Exhibit 99.1.

The information in this Current Report on Form 8-K and the attached Exhibit shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.

Section 9 — Financial Statements and Exhibits

Item 9.01 Financial Statements and Exhibits.

Exhibit No.	Description
99.1	Text of press release dated February 9, 2010.

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 hereunto duly authorized.

HNI CORPORATION

Date: February 9, 2010	By	/s/ Steven M. Bradford
		Steven M. Bradford
		Vice President, General Counsel and Secretary

Exhibit Index

Exhibit No.	Description
99.1	Text of press release dated February 9, 2010.

m:3px double #000000;padding-left:2px;padding-top:2px;padding-bottom:2px;">
$
167,841

$
353,385

Supplemental disclosure of cash flow information:

Cash paid for interest (net of amounts capitalized)
$
(488,574
)

$
(461,302
)
Cash received for income taxes, net
42,051

61,245

Supplemental disclosure of non-cash investing and financing transactions:

Property, plant and equipment additions in accounts payable
$
268,932

$
221,155

Issuance of common stock for equity awards
23,394

17,527

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	Sept. 30, 2017	Dec. 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$167,841	$84,476
Accounts receivable, net	807,621	776,289
Accrued unbilled revenues	625,657	729,832
Inventories	616,675	604,226
Regulatory assets	407,639	363,655
Derivative instruments	74,533	38,224
Prepaid taxes	55,788	106,697
Prepayments and other	143,120	138,682
Total current assets	2,898,874	2,842,081
Property, plant and equipment, net	33,949,952	32,841,750
Other assets		
Nuclear decommissioning fund and other investments	2,300,265	2,091,858
Regulatory assets	3,011,462	3,080,867
Derivative instruments	49,124	50,189
Other	259,117	248,532
Total other assets	5,619,968	5,471,446
Total assets	$42,468,794	$41,155,277
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$305,415	$255,529
Short-term debt	514,000	392,000
Accounts payable	992,498	1,044,959
Regulatory liabilities	256,191	220,894
Taxes accrued	427,275	457,392
Accrued interest	147,860	172,901
Dividends payable	182,795	172,456
Derivative instruments	27,659	26,959
Other	486,713	503,953
Total current liabilities	3,340,406	3,247,043
Deferred credits and other liabilities		
Deferred income taxes	7,362,931	6,784,319
Deferred investment tax credits	59,381	63,216
Regulatory liabilities	1,358,558	1,383,212
Asset retirement obligations	2,883,799	2,782,229
Derivative instruments	131,058	148,146
Customer advances	190,995	195,214

Pension and employee benefit obligations	984,794	1,112,366
Other	144,528	223,965
Total deferred credits and other liabilities	13,116,044	12,692,667
Commitments and contingencies		
Capitalization		
Long-term debt	14,572,967	14,194,718
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,762,881 and 507,222,795 shares outstanding at Sept. 30, 2017 and Dec. 31, 2016, respectively	1,269,407	1,268,057
Additional paid in capital	5,888,729	5,881,494
Retained earnings	4,386,050	3,981,652
Accumulated other comprehensive loss	(104,809)	(110,354)
Total common stockholders' equity	11,439,377	11,020,849
Total liabilities and equity	$42,468,794	$41,155,277

See Notes to Consolidated Financial Statements

6

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended Sept. 30, 2017 and 2016						
Balance at June 30, 2016	507,953	$1,269,882	$5,896,394	$3,643,653	$ (106,795)	$10,703,134
Net income				457,795		457,795
Other comprehensive income					1,834	1,834
Dividends declared on common stock				(173,786)		(173,786)
Issuances of common stock	48	120	—			120
Repurchases of common stock	(48)	(120)	(2,021)			(2,141)
Share-based compensation			4,523	(3,537)		986
Balance at Sept. 30, 2016	507,953	$1,269,882	$5,898,896	$3,924,125	$ (104,961)	$10,987,942
Balance at June 30, 2017	507,763	$1,269,407	$5,881,475	$4,079,068	$ (106,795)	$11,123,155
Net income				492,141		492,141
Other comprehensive income					1,986	1,986
Dividends declared on common stock				(184,061)		(184,061)
Share-based compensation			7,254	(1,098)		6,156
Balance at Sept. 30, 2017	507,763	$1,269,407	$5,888,729	$4,386,050	$ (104,809)	$11,439,377

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED) (Continued)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Nine Months Ended Sept. 30, 2017 and 2016						
Balance at Dec. 31, 2015	507,536	$1,268,839	$5,889,106	$3,552,728	$ (109,753)	$10,600,920
Net income				895,902		895,902
Other comprehensive income					4,792	4,792
Dividends declared on common stock				(520,968)		(520,968)
Issuances of common stock	486	1,216	15,110			16,326
Repurchases of common stock	(69)	(173)	(2,810)			(2,983)
Share-based compensation			(2,510)	(3,537)		(6,047)
Balance at Sept. 30, 2016	507,953	$1,269,882	$5,898,896	$3,924,125	$ (104,961)	$10,987,942
Balance at Dec. 31, 2016	507,223	$1,268,057	$5,881,494	$3,981,652	$ (110,354)	$11,020,849
Net income				958,674		958,674
Other comprehensive income					5,545	5,545
Dividends declared on common stock				(551,614)		(551,614)
Issuances of common stock	611	1,527	3,510			5,037
Repurchases of common stock	(71)	(177)	(2,943)			(3,120)
Share-based compensation			6,668	(2,662)		4,006
Balance at Sept. 30, 2017	507,763	$1,269,407	$5,888,729	$4,386,050	$ (104,809)	$11,439,377

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 2017 and Dec. 31, 2016; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and nine months ended Sept. 30, 2017 and 2016; and its cash flows for the nine months ended Sept. 30, 2017 and 2016. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2017 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2016 balance sheet information has been derived from the audited 2016 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2016. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2016, filed with the SEC on Feb. 24, 2017. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2016, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the Financial Accounting Standards Board (FASB) issued Revenue from Contracts with Customers, Topic 606 (Accounting Standards Update (ASU) No. 2014-09), which provides a new framework for the recognition of revenue. Xcel Energy expects its adoption will primarily result in increased disclosures regarding revenue related to arrangements with customers, as well as separate presentation of alternative revenue programs. Xcel Energy currently expects to implement the standard on a modified retrospective basis, which requires application to contracts with customers effective Jan. 1, 2018, with the cumulative impact on contracts not yet completed as of Dec. 31, 2017 recognized as an adjustment to the opening balance of retained earnings.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01), which eliminates the available-for-sale classification for marketable equity securities and also replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are to be recognized in earnings. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy expects that as a result of application of accounting principles for rate regulated entities, changes in the fair value of the securities in the nuclear decommissioning fund, currently classified as available-for-sale, will continue to be deferred to a regulatory asset, and that the overall impacts of the

Jan. 1, 2018 adoption will not be material.

Leases — In February 2016, the FASB issued Leases, Topic 842 (ASU No. 2016-02), which for lessees requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. Xcel Energy has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard. As such, agreements entered prior to Jan. 1, 2017 that are currently considered leases are expected to be recognized on the consolidated balance sheet, including contracts for use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for natural gas-fueled generating facilities. Xcel Energy expects that similar agreements entered after Dec. 31, 2016 will generally qualify as leases under the new standard, but has not yet completed its evaluation of certain other contracts, including arrangements for the secondary use of assets, such as land easements.

Table of Contents

Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07), which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. Xcel Energy expects that as a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the current ratemaking treatment and that the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2017.

Recently Adopted

Stock Compensation — In March 2016, the FASB issued Improvements to Employee Share-Based Payment Accounting, Topic 718 (ASU No. 2016-09), which simplifies accounting and financial statement presentation for share-based payment transactions. The guidance requires that the difference between the tax deduction available upon settlement of share-based equity awards and the tax benefit accumulated over the vesting period be recognized as an adjustment to income tax expense. Xcel Energy adopted the guidance in 2016, resulting in immaterial 2016 adjustments to income tax expense and changes in classification of cash flows related to tax withholding in the consolidated statements of cash flows for the years ended Dec. 31, 2016, 2015 and 2014.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Accounts receivable, net		
Accounts receivable	$859,242	$827,112
Less allowance for bad debts	(51,621)	(50,823)
	$807,621	$776,289

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Inventories		
Materials and supplies	$320,195	$312,430
Fuel	166,173	181,752
Natural gas	130,307	110,044
	$616,675	$604,226

(Thousands of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Property, plant and equipment, net		
Electric plant	$39,067,098	$38,220,765
Natural gas plant	5,563,536	5,317,717
Common and other property	2,028,743	1,888,518
Plant to be retired [(a)]	11,412	31,839
Construction work in progress	1,861,576	1,373,380
Total property, plant and equipment	48,532,365	46,832,219
Less accumulated depreciation	(14,982,709)	(14,381,603)
Nuclear fuel	2,668,586	2,571,770
Less accumulated amortization	(2,268,290)	(2,180,636)
	$33,949,952	$32,841,750

(a) In the third quarter of 2017, PSCo early retired Valmont Unit 5 and converted Cherokee Unit 4 from a coal-fueled generating facility to natural gas. PSCo also expects Craig Unit 1 to be early retired in approximately 2025. Amounts are presented net of accumulated depreciation.

10

Table of Contents

4. Income Taxes

Except to the extent noted below, Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2016 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Loss Carryback Claims — In 2012-2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audits — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2009 through 2011 and 2012 through 2013 federal income tax returns, following extensions, expires in June 2018 and October 2018, respectively.

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims that would have resulted in $14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In the third quarter of 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). After evaluating the proposed adjustment, Xcel Energy filed a protest with the IRS. Xcel Energy anticipates the issue will be forwarded to Appeals. As of Sept. 30, 2017, Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Sept. 30, 2017, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2012

- In 2016, Minnesota began an audit of years 2010 through 2014. As of Sept. 30, 2017, Minnesota had not proposed any material adjustments;
- In 2016, Texas began an audit of years 2009 and 2010, and, in September 2017, began an audit of 2011. As of Sept. 30, 2017, Texas had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. As of Sept. 30, 2017, Wisconsin had not proposed any material adjustments; and
- As of Sept. 30, 2017, there were no other state income tax audits in progress.

Unrecognized Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Unrecognized tax benefit — Permanent tax positions	$20.6	$ 29.6
Unrecognized tax benefit — Temporary tax positions	22.2	104.1
Total unrecognized tax benefit	$42.8	$ 133.7

11

Table of Contents

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Sept. 30, 2017	Dec. 31, 2016
NOL and tax credit carryforwards	$(29.2)	$(43.8)

It is reasonably possible that Xcel Energy’s amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audits resume, the Minnesota, Texas and Wisconsin audits progress, and other state audits resume. As the IRS Appeals, Minnesota, Texas and Wisconsin audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $19 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits are as follows:

(Millions of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Payable for interest related to unrecognized tax benefits at beginning of period	$(3.4)	$ (0.1)
Interest income (expense) related to unrecognized tax benefits recorded during the period	1.9	(3.3)
Payable for interest related to unrecognized tax benefits at end of period	$(1.5)	$ (3.4)

No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2017 or Dec. 31, 2016.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2016 and in Note 5 to 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 other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

Minnesota 2016 Multi-Year Electric Rate Case — In June 2017, the MPUC issued a written order. NSP-Minnesota estimated the total rate increase to be approximately $245 million over the four-year period covering 2016-2019.

Key terms:
- Four-year period covering 2016-2019;
- Annual sales true-up with decoupling subject to a 3 percent cap;
- Return on equity (ROE) of 9.2 percent and an equity ratio of 52.5 percent;
- Nuclear related costs will not be considered provisional;
- Continued use of all existing riders, however no new riders may be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019;
- Four-year stay-out provision for rate cases;

- Property tax true-up mechanism for 2017-2019; and
- Capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, Incremental)	2016	2017	2018	2019	Total
Revenues	$74.99	$59.86	$ —	$50.12	$184.97
NSP-Minnesota’s sales true-up	59.95	—	—	(0.20)	59.75
Total rate impact	$134.94	$59.86	$ —	$49.92	$244.72

12

Table of Contents

In September 2017, the MPUC ordered NSP-Minnesota to collect final rates beginning March 1, 2017 (requested date was Jan. 1, 2017). As a result, NSP-Minnesota estimates the adjusted total rate increase to be approximately $240 million over the four-year period covering 2016-2019.

Annual Automatic Adjustment of Fuel Clause Charges — In May 2017, the MPUC voted to disallow approximately $4.4 million of replacement energy costs for the Prairie Island (PI) nuclear facility outages allocated to the Minnesota jurisdiction in 2015. This disallowance was recognized in the second quarter of 2017. In September 2017, the Minnesota Department of Commerce (DOC) recommended the MPUC should hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages under certain circumstances. In addition, the DOC is continuing its review of nuclear costs and operations focusing on PI under the initial rate case and resource plan orders as well as the recently finalized rate case.

NSP-Wisconsin

Pending Regulatory Proceeding — Public Service Commission of Wisconsin (PSCW)

Wisconsin 2018 Electric and Natural Gas Rate Case — In May 2017, NSP-Wisconsin filed a request with the PSCW to increase electric rates by $24.7 million, or 3.6 percent, and natural gas rates by $12.0 million, or 10.1 percent, effective Jan. 1, 2018. The rate filing is based on a 2018 forecast test year, a ROE of 10.0 percent, an equity ratio of 52.53 percent and a forecasted rate base of approximately $1.2 billion for the electric utility and $138.4 million for the natural gas utility.

In September 2017, the PSCW Staff and the intervenors filed testimony. The PSCW Staff recommended an electric rate increase of $10.9 million, or 1.6 percent, and a natural gas rate increase of $9.9 million, or 8.3 percent, based on a ROE of 9.8 percent and an equity ratio of 51.45 percent.

A PSCW decision is anticipated in December 2017 with new rates effective in January 2018.

PSCo

Pending Regulatory Proceedings — Colorado Public Utilities Commission (CPUC)

Colorado 2017 Multi-Year Electric Rate Case — In October 2017, PSCo filed a multi-year request with the CPUC seeking to increase electric rates approximately $245 million over four years. The request, summarized below, is based on forecast test years (FTY) ending Dec. 31, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	2021	Total
Revenue request	$74.6	$74.9	$59.7	$35.7	$244.9
Clean Air Clean Jobs Act (CACJA) revenue conversion to base rates [(a)]	90.4	—	—	—	90.4
Transmission Cost Adjustment (TCA) revenue conversion to base rates [(a)]	42.7	—	—	—	42.7
Total [(b)]	$207.7	$74.9	$59.7	$35.7	$378.0
Expected year-end rate base (billions of dollars) [(b)]	$6.8	$7.1	$7.3	$7.4	

(a) The roll-in of each of the TCA and CACJA rider revenues into base rates will not have an impact on total customer bills or total revenue as these costs are already being recovered through a rider. Transmission investments for 2019 through 2021 will be recovered through the TCA rider.

(b)

This base rate request does not include the impacts associated with the renewable energy standard adjustment and retail electric commodity adjustment for the Rush Creek wind investments or any impacts of the proposed Colorado Energy Plan.

Final rates are expected to be effective in June 2018. PSCo also proposed a stay-out provision and earnings test through 2021.

Table of Contents

Colorado 2017 Multi-Year Natural Gas Rate Case — In June 2017, PSCo filed a multi-year request with the CPUC seeking to increase retail natural gas rates approximately $139 million over three years. The request, detailed below, is based on FTYs, a 10.0 percent ROE and an equity ratio of 55.25 percent.

Revenue Request (Millions of Dollars)	2018	2019	2020	Total
Revenue request	$63.2	$32.9	$42.9	$139.0
Pipeline System Integrity Adjustment (PSIA) revenue conversion to base rates [a]	—	93.9	—	93.9
Total	$63.2	$126.8	$42.9	$232.9
Expected year-end rate base (billions of dollars) [b]	$1.5	$2.3	$2.4	

(a) The roll-in of PSIA rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. PSCo plans to request new PSIA rates for 2018 in November 2017. The recovery of incremental PSIA related investments in 2019 and 2020 are included in the base rate request.

(b) The additional rate base in 2019 predominantly reflects the roll-in of capital associated with the PSIA rider.

In October 2017, several parties filed answer testimony. The CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), recommended a single 2016 historic test year (HTY), based on an average 13-month rate base, and opposed a multi-year plan (MYP). The Staff and OCC recommended an equity capital structure of 48.73 percent and 51.2 percent, respectively. Both the Staff and the OCC recommended the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through base rates, subject to a future rate case.

The following represents adjustments to PSCo’s filed request made by Staff and OCC for 2018:

(Millions of Dollars)	Staff	OCC
Filed 2018 new revenue request	$63.2	$63.2
Impact of the change in test year	4.4	4.4
PSCo’s filed 2016 HTY	$67.6	$67.6
Recommended adjustments:		
ROE (9.0 percent)	(13.5)	(13.5)
Capital structure and cost of debt	(10.2)	(7.5)
Change in amortization period	(5.4)	—
Prepaid pension and retiree medical assets	(5.2)	—
Change from 2016 year end to average rate base	(4.8)	(4.8)
Other, net	(5.0)	(5.5)
Total adjustments	$(44.1)	$(31.3)
Total recommended rate increase	$23.5	$36.3

The next steps in the procedural schedule are as follows:

- Rebuttal testimony — Nov. 3, 2017;
- Intervenor sur-rebuttal testimony — Nov. 15, 2017;
- Hearings — Dec. 11 - 15 and 18 - 19, 2017; and
- Statements of position — Jan. 19, 2018.

Interim rates, subject to refund, are expected to be effective Jan. 1, 2018. A final decision by the CPUC is anticipated in March 2018.

Annual Electric Earnings Test — PSCo must share with customers earnings that exceed the authorized ROE of 9.83 percent for 2015 through 2017, as part of an annual earnings test. The current estimate of the 2017 earnings test, based on annual forecasted information, did not result in the recognition of a liability as of Sept. 30, 2017.

14

Table of Contents

SPS

Pending Regulatory Proceedings — Public Utility Commission of Texas (PUCT)

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $42.1 million. In 2015, the PUCT approved an overall rate decrease of approximately $4.0 million, net of rate case expenses. In April 2016, SPS filed an appeal, with the Texas State District Court, of the PUCT's order that had denied SPS' request for rehearing on certain items in SPS' Texas 2015 electric rate case related to capital structure, incentive compensation and wholesale load reductions. In March 2017, the Travis County District Court denied SPS' appeal. In April 2017, SPS appealed the District Court's decision to the Court of Appeals.

Texas 2017 Electric Rate Case — In August 2017, SPS filed a $66.4 million, or 7.1 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on the 12-month period ended June 30, 2017, with the final three months based on estimates, a requested ROE of 10.25 percent, a Texas retail electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

In October 2017, SPS revised its request to $54.6 million, or 5.8 percent, which reflects updated actual results. In addition, approximately $4.4 million of rate case expenses was bifurcated into a separate docket.

The following table summarizes SPS' revised rate increase request:

Revenue Request (Millions of Dollars)	
Incremental revenue request	$69.2
Transmission Cost Recovery Factor (TCRF) revenue conversion to base rates [a]	(14.6)
Net revenue increase request	$54.6

(a) The roll-in of the TCRF rider revenue into base rates will not have an impact on customer bills or total revenue as these costs are already being recovered through the rider. SPS can request another TCRF rider after the conclusion of this rate case to recover transmission investments subsequent to June 30, 2017.

Key dates in the procedural schedule are as follows:

- Intervenors' direct testimony — Feb. 22, 2018;
- PUCT Staff direct testimony — March 1, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — March 22, 2018;
- SPS' rebuttal testimony — March 23, 2018;
- Hearings — April 10 - 20, 2018; and
- Statutory deadline — Aug. 31, 2018.

The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the third quarter of 2018.

Pending Regulatory Proceeding — New Mexico Public Regulation Commission (NMPRC)

New Mexico 2016 Electric Rate Case — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41.4 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ending June 30, 2018.

In April 2017, the NMPRC dismissed SPS' rate case. In May 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision from the New Mexico Supreme Court is not expected until the second or third quarter of 2018.

SPS plans to file another base rate case by November 2017 utilizing a HTY ending June 2017.

Table of Contents

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaints — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners (TOs), including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, and the removal of ROE adders (including those for Regional Transmission Organization (RTO) membership), effective Nov. 12, 2013.

In December 2015, an administrative law judge (ALJ) recommended the FERC approve a base ROE of 10.32 percent for the MISO TOs. The ALJ found the existing 12.38 percent ROE to be unjust and unreasonable. The recommended 10.32 percent ROE applied a FERC ROE policy adopted in a June 2014 order (Opinion 531). The FERC approved the ALJ recommended 10.32 percent base ROE in an order issued in September 2016. This ROE would be applicable for the 15 month refund period from Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE would be 10.82 percent, including a 50 basis point adder for RTO membership. Various parties requested rehearing of the September 2016 order. The requests are pending FERC action.

In February 2015, a second complaint seeking to reduce the MISO ROE from 12.38 percent to 8.67 percent prior to any adder was filed with the FERC, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. In June 2016, the ALJ recommended a ROE of 9.7 percent, applying the methodology adopted by the FERC in Opinion 531. A final FERC decision on the second ROE complaint was expected later in 2017, but in April 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) by opinion, vacated and remanded Opinion 531. It is unclear how the D.C. Circuit's opinion to vacate and remand Opinion 531 will affect the September 2016 FERC order or the timing and outcome of the second ROE complaint. The MISO TOs are evaluating the impact of the D.C. Circuit ruling on the November 2013 and February 2015 ROE complaints. In September 2017, certain MISO TOs (not including NSP-Minnesota and NSP-Wisconsin) filed a motion to dismiss the second ROE complaint. The motion to dismiss is pending FERC action.

As of Sept. 30, 2017, NSP-Minnesota has processed the refunds for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE provided in the September 2016 FERC order. NSP-Minnesota has also recognized a current refund liability consistent with the best estimate of the final ROE for the Feb. 12, 2015 to May 11, 2016 complaint period.

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant-funded, or "sponsored," transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In July 2016, the FERC granted SPP's request for a waiver to allow SPP to recover the charges not billed since 2008. In November 2016, SPP billed SPS a net amount, for the period from 2008 through August 2016, of $12.8 million for these charges, to be paid over a five-year period commencing November 2016. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. On the retail level, in October 2016, SPS filed applications for deferred accounting and future recovery of related costs in New Mexico and Texas. In December 2016, SPS' New Mexico application was consolidated with its base rate case, but the NMPRC dismissed that rate case in April 2017. SPS will seek recovery of these SPP charges in its next New Mexico base rate case by November 2017. In March 2017, SPS withdrew its Texas application and is now seeking to recover these SPP charges in its pending rate case filed in August 2017.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed on and after November 2016 asserting that SPP has assessed upgrade charges to SPS even where SPS' transmission service was not dependent upon the upgrade as required by the SPP OATT. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings. Also in October 2017, SPP made adjustments to its previous calculations of upgrade charges to SPP customers, and the impact was immaterial to SPS.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5 above, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2016, and in Notes 5 and 6 to the
consolidated financial statements included in Xcel Energy Inc.'s Quarterly Reports 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 commitments and contingent liabilities and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

Table of Contents

PPAs

Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the associated independent power producing entity.

The Xcel Energy utility subsidiaries had approximately 3,537 megawatts (MW) of capacity under long-term PPAs as of Sept. 30, 2017 and Dec. 31, 2016, with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through 2041.

Guarantees and Bond Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum guarantee or indemnity amount. As of Sept. 30, 2017 and Dec. 31, 2016, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy:

(Millions of Dollars)	Sept. 30, 2017	Dec. 31, 2016
Guarantees issued and outstanding	$19.1	$ 18.8
Current exposure under these guarantees	—	0.1
Bonds with indemnity protection	51.9	43.0

Other Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Environmental Contingencies

Ashland Manufactured Gas Plant (MGP) Site — NSP-Wisconsin was named a potentially responsible party (PRP) for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Site) includes NSP-Wisconsin property, previously operated as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park); and an area of Lake Superior's Chequamegon Bay adjoining the park.

In 2012, NSP-Wisconsin agreed to remediate the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site), under a settlement agreement with the United States Environmental Protection Agency (EPA). In January 2017, NSP-Wisconsin agreed to remediate the Phase II Project Area (the Sediments), under a settlement agreement with the EPA. The settlement was approved by the U.S. District Court for the Western District of Wisconsin. NSP-Wisconsin initiated field activities to perform a full scale wet dredge remedy of the Sediments in 2017 and anticipates completion of restoration activities in 2018.

The current remediation cost estimate for the entire site (both the Phase I Project Area and the Sediments) is approximately $162.9 million, of which approximately $131.8 million has been spent. As of Sept. 30, 2017 and Dec. 31, 2016, NSP-Wisconsin had recorded a total liability of $31.1 million and $64.3 million, respectively, for the entire site.

Table of Contents

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period and to apply a three percent carrying cost to the unamortized regulatory asset. In May 2017, NSP-Wisconsin filed a natural gas rate case which included recovery of additional expenses associated with remediating the Site. If approved, the annual recovery of MGP clean-up costs would increase from $12.4 million in 2017 to $18.1 million in 2018.

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials from the right-of-way and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). NSP-Minnesota has recommended that targeted source removal of impacted soils and historic MGP infrastructure should be performed. The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017. It is anticipated that remediation activities will be performed in 2018, although the timing and final scope of remediation is dependent on whether reasonable access is provided to NSP-Minnesota to perform and implement the approved cleanup plan. Access agreements have been reached with a majority of the property owners in the area to perform the work. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until January 2018.

As of Sept. 30, 2017 and Dec. 31, 2016, NSP-Minnesota had recorded a liability of $16.2 million and $11.3 million, respectively, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately $23.0 million, of which approximately $6.8 million has been spent. In December 2015, the North Dakota Public Service Commission (NDPSC) approved NSP-Minnesota's request to defer costs associated with the Fargo MGP Site, resulting in deferral of all investigation and response costs with the exception of approximately 12 percent allocable to the Minnesota jurisdiction. Uncertainties related to the liability recognized include obtaining access to perform the approved remediation (including the prospective purchase of the historic MGP property), and the potential for contributions from entities that may be identified as PRPs.

Other MGP and Landfill Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP and landfill sites. Xcel Energy has identified eleven sites across its service territories in addition to the sites in Ashland, Wis. and Fargo, N.D., where former MGP or landfill disposal activities have or may have resulted in site contamination and are under current investigation and/or remediation. At some or all of these sites, there are other parties that may have responsibility for some portion of any remediation. Xcel Energy anticipates that the majority of the investigation or remediation at these sites will continue through at least 2018. Xcel Energy had accrued $4.5 million and $2.0 million for these sites as of Sept. 30, 2017 and Dec. 31, 2016, respectively. There may be insurance recovery and/or recovery from other PRPs to offset any costs incurred. Xcel Energy anticipates that any significant amounts incurred will be recovered from customers.

Environmental Requirements

Water and Waste

Federal Clean Water Act (CWA) Waters of the United States Rule — In 2015, the EPA and the U.S. Army Corps of Engineers (Corps) published a final rule that significantly expanded the types of water bodies regulated under the CWA and broadened the scope of waters subject to federal jurisdiction. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule and subsequently ruled that it, rather than the federal district courts, had jurisdiction over challenges to the rule. In January 2017, the U.S. Supreme Court agreed to resolve the dispute as to which court should hear challenges to the rule. A ruling is expected in the first quarter of 2018.

In February 2017, President Trump issued an executive order requiring the EPA and the Corps to review and revise the final rule. On June 27, 2017, the agencies issued a proposed rule that rescinds the 2015 final rule and reinstates the prior 1986 definition of “Water of the U.S.” The agencies are also undertaking a rulemaking to develop a new definition of “Waters of the U.S.”

Federal CWA Effluent Limitations Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. In September 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport water until November 2020 while the agency conducts a rulemaking process to potentially revise the effluent limitations and pretreatment standards for these waste streams.

Table of Contents

Air

Greenhouse Gas (GHG) Emission Standard for Existing Sources (Clean Power Plan or CPP) — In 2015, the EPA issued its final rule for existing power plants. Among other things, the rule requires that state plans include enforceable measures to ensure emissions from existing power plants achieve the EPA's state-specific interim (2022-2029) and final (2030 and thereafter) emission performance targets.

The CPP was challenged by multiple parties in the D.C. Circuit Court. In February 2016, the U.S. Supreme Court issued an order staying the final CPP rule. In September 2016, the D.C. Circuit Court heard oral arguments in the consolidated challenges to the CPP. The stay will remain in effect until the D.C. Circuit Court reaches its decision and the U.S. Supreme Court either declines to review the lower court's decision or reaches a decision of its own.

In March 2017, President Trump signed an executive order requiring the EPA Administrator to review the CPP rule and if appropriate, publish proposed rules suspending, revising or rescinding it. Accordingly, the EPA has requested that the D.C. Circuit Court hold the litigation in abeyance until the EPA completes its work under the executive order. The D.C. Circuit granted the EPA's request and is holding the litigation in abeyance, while considering briefs by the parties on whether the court should remand the challenges to the EPA rather than holding them in abeyance, determining whether and how the court continues or ends the stay that currently applies to the CPP.

In October 2017, the EPA published a proposed rule to repeal the CPP, based on an analysis that the CPP exceeds the EPA's statutory authority under the Clean Air Act (CAA). The EPA will take public comment on the proposal for 60 days. The EPA stated it has not yet determined whether it will promulgate a new rule to regulate GHG emissions from existing electric generating units.

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. The Best Available Retrofit Technology (BART) requirements of the EPA's regional haze rules require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. Under BART, regional haze plans identify facilities that will have to reduce Sulfur Dioxide (SO_2), Nitrogen Oxide (NOx) and particulate matter emissions and set emission limits for those facilities. BART requirements can also be met through participation in interstate emission trading programs such as the Clean Air Interstate Rule (CAIR) and its successor, Cross-State Air Pollution Rule (CSAPR). The requirements of the regional haze plans developed by Minnesota and Colorado that apply to NSP-Minnesota and PSCo have been fully approved and implemented in those states. States are required to revise their plans every ten years. The next plans for Minnesota and Colorado will be due in 2021. Texas' first regional haze plan has undergone federal review as described below.

BART Determinations for Texas: Texas developed a State Implementation Plan (SIP) that found the CAIR equal to BART for electric generating units. As a result, no additional controls beyond CAIR compliance would have been required. In 2014, the EPA proposed to approve the BART portion of the SIP, with substitution of CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that deferred its approval of CSAPR compliance as BART until the EPA considered further adjustments to CSAPR emission budgets under the D.C. Circuit Court's remand of the Texas SO_2 emission budgets. The EPA then published a proposed rule in January 2017 that could have had the effect of requiring installation of dry scrubbers to reduce SO_2 emissions from Harrington Units 1 and 2. Investment costs associated with dry scrubbers for Harrington Units 1 and 2 could have been approximately $400 million. In September 2017, the EPA issued a final rule adopting a Texas only SO_2 trading program as a BART Alternative. The program allocated SO_2 allowances to electric generating units in Texas, including all three Harrington units and both Tolk units, consistent with their allocation under CSAPR, resulting in an emissions budget for Texas that is consistent with the EPA's 2012 rule. SPS expects the allowance allocations to be sufficient for SO_2 emissions from Harrington and Tolk units in 2019 and future years. The anticipated costs of compliance are not expected to have a material impact on the results of operations, financial position or cash flows; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Reasonable Progress Rule: In January 2016, the EPA adopted a final rule establishing a federal implementation plan for the state of Texas, which imposed SO_2 emission limitations that reflect the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be approximately $600 million. SPS appealed the EPA’s decision and requested a stay of the final rule. The United States Court of Appeals for the Fifth Circuit (Fifth Circuit) granted the stay. In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, while leaving the stay in effect. The Fifth Circuit is now holding the case in abeyance until the EPA completes its reconsideration of the rule. In the final BART rule that affects Tolk and Harrington described above, the EPA noted that it will address the remanded rule in a future action. Such a rule will address whether further SO_2 emission reductions are needed at Tolk to address the “reasonable progress” requirements of the regional haze program. The risk of these controls being imposed along with the risk of investments to provide additional cooling water to Tolk have caused SPS to seek to decrease the remaining depreciable life of the Tolk units.

Table of Contents

Revisions to the National Ambient Air Quality Standard (NAAQS) for Ozone — In 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In areas where Xcel Energy operates, current monitored air quality concentrations comply with the new standard in the Twin Cities Metropolitan Area in Minnesota and meet the 70 ppb level in the Texas panhandle. In documents issued with the new standard, the EPA projects that both areas will meet the new standard. The Denver Metropolitan Area is currently not meeting the prior ozone standard and will therefore not meet the new, more stringent standard, however PSCo's scheduled retirement of coal fired plants in Denver that began in 2011 and was completed in August 2017, should help in any plan to mitigate non-attainment. In August 2017, the EPA withdrew its prior decision delaying designations of nonattainment areas under the 2015 ozone NAAQS to October 2018. The CAA requires areas to be designated within two years after a revision to the NAAQS but allows a one year extension if the EPA has insufficient information on which to base a decision. The EPA is now re-assessing to what extent it has sufficient information to make designations in October 2017 and whether in some cases an extension is still necessary.

Legal Contingencies

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. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

Gas Trading Litigation — e prime, inc. (e prime) is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits were commenced against e prime and Xcel Energy (and NSP-Wisconsin, in two instances) between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices.

e prime, Xcel Energy and its other affiliates were sued along with several other gas marketing companies. These cases were all consolidated in the U.S. District Court in Nevada. Six of the cases remain active, which includes one multi-district litigation (MDL) matter consisting of a Colorado class (Breckenridge), a Wisconsin class (Arandell Corp.), a Missouri class, a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." A motion for class certification was denied and plaintiffs have appealed the ruling to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). Motions for summary judgment were granted by the MDL judge in favor of e prime and Xcel Energy in Sinclair Oil and Farmland. Plaintiffs in both cases appealed this decision to the Ninth Circuit. Motions for summary judgment were also filed by defendants, including e prime, in all of the remaining lawsuits. These motions were denied and e prime subsequently filed an appeal in September 2017. Dates for all matters pending before the Ninth Circuit have not been scheduled. Xcel Energy, NSP-Wisconsin and e prime have concluded that a loss is remote.

Line Extension Disputes — In December 2015, Development Recovery Company (DRC) filed a lawsuit in Denver State Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements entered into by PSCo and various developers. The dispute involves claims by over fifty developers. In May 2016, the district court granted PSCo's motion to dismiss the lawsuit, concluding that jurisdiction over this dispute resides with the CPUC. In June 2016, DRC appealed the district court's dismissal of the lawsuit, and the Colorado Court of Appeals affirmed the lower court decision in favor of PSCo. In July 2017, DRC filed a petition to appeal the decision with the Colorado Supreme Court. It is uncertain whether the Colorado Supreme Court will grant the petition. DRC also brought a proceeding before the CPUC as assignee on behalf of two developers, Ryland Homes and Richmond Homes of Colorado. In March 2016, the ALJ issued an order rejecting DRC's claims for additional allowances and refunds. In June 2016, the ALJ's determination was approved by the CPUC. DRC did not file a request for reconsideration before the CPUC contesting the decision, but filed an appeal in the Denver District Court in August 2016. In July 2017, a stipulation to dismiss this lawsuit with prejudice was filed on behalf of all parties and granted by the Denver District Court.

Table of Contents

PSCo has concluded that a loss is remote with respect to this matter as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. Also, if a loss were sustained, PSCo believes it would be allowed to recover these costs through traditional regulatory mechanisms. The amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. 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.

Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. 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

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2017 and Dec. 31, 2016, there were $28 million and $19 million, respectively, of letters of credit outstanding under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

As of Sept. 30, 2017, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility (a)	Drawn (b)	Available
Xcel Energy Inc.	$ 1,000	$ 422	$ 578
PSCo	700	4	696
NSP-Minnesota	500	21	479

SPS	400	3	397
NSP-Wisconsin	150	92	58
Total	$ 2,750	$ 542	$ 2,208

(a) These credit facilities expire in June 2021.

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

21

Table of Contents

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding as of Sept. 30, 2017 and Dec. 31, 2016.

Long-Term Borrowings

During 2017, Xcel Energy Inc. and its utility subsidiaries issued 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; and
- NSP-Minnesota issued $600 million of 3.60 percent first mortgage bonds due Sept. 15, 2047.

Debt Redemption

- 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.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value (NAV).

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Table of Contents

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as financial transmission rights (FTRs). FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes the cleared prices for each FTR for the most recent auction.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited transparency in the auction process, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs, the limited transparency associated with the valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

Nuclear Decommissioning Fund

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. 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.

Unrealized gains for the nuclear decommissioning fund were $511.7 million and $378.6 million as of Sept. 30, 2017 and Dec. 31, 2016, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $10.3 million and $46.9 million as of Sept. 30, 2017 and Dec. 31, 2016, respectively.

Table of Contents

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of Sept. 30, 2017 and Dec. 31, 2016:

	Sept. 30, 2017					
		Fair Value				
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV (b)	Total
Nuclear decommissioning fund (a)						
Cash equivalents	$32,727	$32,727	$—	$ —	$ —	$32,727
Commingled funds:						
Non U.S. equities	257,487	204,502	—	—	86,654	291,156
Emerging market debt funds	97,285	—	—	—	106,842	106,842
Private equity investments	139,185	—	—	—	192,098	192,098
Real estate	129,219	—	—	—	195,506	195,506
Other commingled funds	146,179	14,964	—	—	145,313	160,277
Debt securities:						
Government securities	45,310	—	44,944	—	—	44,944
U.S. corporate bonds	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.

24

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.

25

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:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$ —	$1,502 [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

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2016 Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss		Regulatory Assets and (Liabilities)		Pre-Tax Gains (Losses) Recognized During the Period in Income	
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:

(Thousands of Dollars)	Sept. 30, 2017 Fair Value 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:

	Sept. 30, 2017		Dec. 31, 2016	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	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)

34

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)

35

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.

37

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

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				

44

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);
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- 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

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:

(Thousands of Dollars)	Futures / Forwards 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

(Thousands of Dollars)	Options 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:

(Thousands of Dollars)	Nine Months Ended Sept. 30 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.

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.

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.

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:

	Issuer Purchases of Equity Securities			
Period	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)