XCEL ENERGY INC
Form 10-Q
August 04, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number: 001-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	41-0448030
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall	
Minneapolis, Minnesota	55401
(Address of principal executive offices)	(Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨
(Do not check if smaller reporting company)	

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at August 1, 2016
Common Stock, $2.50 par value	507,952,795 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, which is operated on an integrated basis and is managed by NSP-Minnesota, is referred to collectively as the NSP System. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands, except per share data)

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Operating revenues				
Electric	$2,224,142	$2,213,460	$4,409,261	$4,438,323
Natural gas	258,899	284,131	824,588	1,000,127
Other	16,808	17,543	38,273	38,903
Total operating revenues	2,499,849	2,515,134	5,272,122	5,477,353
Operating expenses				
Electric fuel and purchased power	855,968	904,705	1,717,820	1,854,837
Cost of natural gas sold and transported	90,071	126,667	402,188	599,038
Cost of sales — other	8,332	8,164	16,577	18,213
Operating and maintenance expenses	596,978	594,279	1,174,388	1,180,109
Conservation and demand side management program expenses	55,916	54,141	113,352	107,946
Depreciation and amortization	322,534	274,602	642,554	547,700
Taxes (other than income taxes)	138,469	129,731	283,792	266,357
Loss on Monticello life cycle management/extended power uprate project	—	—	—	129,463
Total operating expenses	2,068,268	2,092,289	4,350,671	4,703,663
Operating income	431,581	422,845	921,451	773,690
Other income, net	1,560	961	5,810	4,122
Equity earnings of unconsolidated subsidiaries	9,617	8,422	22,799	16,198
Allowance for funds used during construction — equity	14,730	12,641	27,843	25,301
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,630 $5,861, $12,966 and $11,559, respectively	162,980	144,222	319,423	289,162
Allowance for funds used during construction — debt	(6,684)	(6,165)	(12,674)	(12,309)
Total interest charges and financing costs	156,296	138,057	306,749	276,853
Income before income taxes	301,192	306,812	671,154	542,458
Income taxes	104,397	109,881	233,047	193,461
Net income	$196,795	$196,931	$438,107	$348,997
Weighted average common shares outstanding:				
Basic	508,930	507,707	508,789	507,359
Diluted	509,490	508,074	509,311	507,747

Earnings per average common share:				
Basic	$0.39	$0.39	$0.86	$0.69
Diluted	0.39	0.39	0.86	0.69
Cash dividends declared per common share	$0.34	$0.32	$0.68	$0.64

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	2016	2015
Net income	$196,795	$196,931	$438,107	$348,997
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $550, $561, $407 and $1,130, respectively	865	883	1,076	1,759
Derivative instruments:				
Net fair value increase, net of tax of $7, $11, $5 and $4, respectively	12	18	8	7
Reclassification of losses to net income, net of tax of $594, $382, $1,198 and $764, respectively	936	600	1,874	1,185
	948	618	1,882	1,192
Marketable securities:				
Net fair value increase, net of tax of $0, $1, $0 and $1, respectively	—	1	—	2
Other comprehensive income	1,813	1,502	2,958	2,953
Comprehensive income	$198,608	$198,433	$441,065	$351,950

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Six Months Ended June 30	
	2016	2015
Operating activities		
Net income	$438,107	$348,997
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	650,336	556,420
Conservation and demand side management program amortization	2,323	2,901
Nuclear fuel amortization	58,267	49,454
Deferred income taxes	252,889	191,164
Amortization of investment tax credits	(2,613)	(2,768)
Allowance for equity funds used during construction	(27,843)	(25,301)
Equity earnings of unconsolidated subsidiaries	(22,799)	(16,198)
Dividends from unconsolidated subsidiaries	22,910	19,754
Share-based compensation expense	24,454	21,420
Loss on Monticello life cycle management/extended power uprate project	—	129,463
Net realized and unrealized hedging and derivative transactions	3,903	13,450
Other	(388)	—
Changes in operating assets and liabilities:		
Accounts receivable	35,042	150,283
Accrued unbilled revenues	65,159	145,781
Inventories	81,880	64,561
Other current assets	69,493	69,080
Accounts payable	27,805	(132,032)
Net regulatory assets and liabilities	34,264	129,595
Other current liabilities	(164,076)	(92,108)
Pension and other employee benefit obligations	(108,562)	(78,681)
Change in other noncurrent assets	(6,363)	684
Change in other noncurrent liabilities	(21,649)	(36,874)
Net cash provided by operating activities	1,412,539	1,509,045
Investing activities		
Utility capital/construction expenditures	(1,413,129)	(1,477,959)
Proceeds from insurance recoveries	1,595	27,237
Allowance for equity funds used during construction	27,843	25,301
Purchases of investment securities	(319,880)	(640,100)
Proceeds from the sale of investment securities	262,321	636,669
Investments in WYCO Development LLC and other	(2,170)	(764)
Other, net	100	(1,407)
Net cash used in investing activities	(1,443,320)	(1,431,023)
Financing activities		
Repayments of short-term borrowings, net	(399,000)	(568,500)
Proceeds from issuance of long-term debt	1,337,430	841,534
Repayments of long-term debt	(579,976)	(454)

Proceeds from issuance of common stock	—	3,409
Purchase of common stock for settlement of equity awards	(789)	—
Dividends paid	(335,113)	(298,022)
Net cash provided by (used in) financing activities	22,552	(22,033)
Net change in cash and cash equivalents	(8,229)	55,989
Cash and cash equivalents at beginning of period	84,940	79,608
Cash and cash equivalents at end of period	$76,711	$135,597
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(293,954)	$(266,840)
Cash received for income taxes, net	61,345	58,598
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$252,370	$206,540
Issuance of common stock for reinvested dividends and 401(k) plans	13,497	30,498

See Notes to Consolidated Financial Statements

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

	June 30, 2016	Dec. 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$76,711	$84,940
Accounts receivable, net	689,564	724,606
Accrued unbilled revenues	589,708	654,867
Inventories	526,785	608,584
Regulatory assets	325,690	344,630
Derivative instruments	46,953	33,842
Deferred income taxes	206,644	140,219
Prepaid taxes	115,898	163,023
Prepayments and other	126,146	155,734
Total current assets	2,704,099	2,910,445
Property, plant and equipment, net	31,823,282	31,205,851
Other assets		
Nuclear decommissioning fund and other investments	1,987,474	1,902,995
Regulatory assets	2,886,250	2,858,741
Derivative instruments	50,644	51,083
Other	38,415	32,581
Total other assets	4,962,783	4,845,400
Total assets	$39,490,164	$38,961,696
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$710,151	$657,021
Short-term debt	447,000	846,000
Accounts payable	921,973	960,982
Regulatory liabilities	279,755	306,830
Taxes accrued	330,398	438,189
Accrued interest	169,309	166,829
Dividends payable	172,704	162,410
Derivative instruments	26,542	29,839
Other	448,549	490,197
Total current liabilities	3,506,381	4,058,297
Deferred credits and other liabilities		
Deferred income taxes	6,619,681	6,293,661
Deferred investment tax credits	65,806	68,419
Regulatory liabilities	1,343,889	1,332,889
Asset retirement obligations	2,671,320	2,608,562
Derivative instruments	156,357	168,311

Customer advances	212,565	228,999
Pension and employee benefit obligations	825,614	941,002
Other	280,647	261,756
Total deferred credits and other liabilities	12,175,879	11,903,599
Commitments and contingencies		
Capitalization		
Long-term debt	13,104,770	12,398,880
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 507,952,795 and 507,535,523 shares outstanding at June 30, 2016 and Dec. 31, 2015, respectively	1,269,882	1,268,839
Additional paid in capital	5,896,394	5,889,106
Retained earnings	3,643,653	3,552,728
Accumulated other comprehensive loss	(106,795)	(109,753)
Total common stockholders' equity	10,703,134	10,600,920
Total liabilities and equity	$39,490,164	$38,961,696

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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 June 30, 2016 and 2015						
Balance at March 31, 2015	506,664	$1,266,659	$5,844,995	$3,209,904	$ (106,688)	$10,214,870
Net income				196,931		196,931
Other comprehensive income					1,502	1,502
Dividends declared on common stock				(163,190)		(163,190)
Issuances of common stock	295	739	9,316			10,055
Share-based compensation			8,898			8,898
Balance at June 30, 2015	506,959	$1,267,398	$5,863,209	$3,243,645	$ (105,186)	$10,269,066
Balance at March 31, 2016	507,953	$1,269,882	$5,889,939	$3,620,421	$ (108,608)	$10,671,634
Net income				196,795		196,795
Other comprehensive income					1,813	1,813
Dividends declared on common stock				(173,563)		(173,563)
Issuances of common stock	—	—	(187)			(187)
Share-based compensation			6,642			6,642
Balance at June 30, 2016	507,953	$1,269,882	$5,896,394	$3,643,653	$ (106,795)	$10,703,134

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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
Six Months Ended June 30, 2016 and 2015						
Balance at Dec. 31, 2014	505,733	$1,264,333	$5,837,330	$3,220,958	$ (108,139)	$10,214,482
Net income				348,997		348,997
Other comprehensive income					2,953	2,953
Dividends declared on common stock				(326,310)		(326,310)
Issuances of common stock	1,226	3,065	10,209			13,274
Share-based compensation			15,670			15,670
Balance at June 30, 2015	506,959	$1,267,398	$5,863,209	$3,243,645	$ (105,186)	$10,269,066
Balance at Dec. 31, 2015	507,536	$1,268,839	$5,889,106	$3,552,728	$ (109,753)	$10,600,920
Net income				438,107		438,107
Other comprehensive income					2,958	2,958
Dividends declared on common stock				(347,182)		(347,182)
Issuances of common stock	417	1,043	(3,942)			(2,899)
Purchase of common stock for settlement of equity awards			(789)			(789)
Share-based compensation			12,019			12,019
Balance at June 30, 2016	507,953	$1,269,882	$5,896,394	$3,643,653	$ (106,795)	$10,703,134

See Notes to Consolidated Financial Statements

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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 June 30, 2016 and Dec. 31, 2015; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and six months ended June 30, 2016 and 2015; and its cash flows for the six months ended June 30, 2016 and 2015. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2016 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, 2015 balance sheet information has been derived from the audited 2015 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2015. 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, 2015, filed with the SEC on Feb. 19, 2016. 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, 2015, 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 framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. The new guidance also includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers. The guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

Presentation of Deferred Taxes — In November 2015, the FASB issued Balance Sheet Classification of Deferred Taxes, Topic 740 (ASU No 2015-17), which eliminates the requirement to present deferred tax assets and liabilities as current and noncurrent on the balance sheet based on the classification of the related asset or liability, and instead requires classification of all deferred tax assets and liabilities as noncurrent. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Other than the prescribed classification of all deferred tax assets and liabilities as noncurrent, Xcel Energy does not expect the implementation of ASU 2015-17 to have a material impact on its consolidated financial statements.

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 among other changes in accounting and disclosure requirements, replaces the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes, and also eliminates the available-for-sale classification for marketable equity securities. Under the new guidance, 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 is currently evaluating the impact of adopting ASU 2016-01 on its consolidated financial statements.

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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 all leases. Additionally, for leases that qualify as finance leases, the guidance requires expense recognition consisting of amortization of the right-of-use asset as well as interest on the related lease liability using the effective interest method. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018, and early adoption is permitted. Xcel Energy is currently evaluating the impact of adopting ASU 2016-02 on its consolidated financial statements.

Stock Compensation — In March 2016, the FASB issued Improvements to Employee Share-Based Payment Accounting, Topic 718 (ASU 2016-09), which amends existing guidance to simplify several aspects of accounting and presentation for share-based payment transactions, including the accounting for income taxes and forfeitures, as well as presentation in the statement of cash flows. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2016, and early adoption is permitted. Xcel Energy does not expect the implementation of ASU 2016-09 to have a material impact on its consolidated financial statements.

Recently Adopted

Consolidation — In February 2015, the FASB issued Amendments to the Consolidation Analysis, Topic 810 (ASU No. 2015-02), which reduces the number of consolidation models and amends certain consolidation principles related to variable interest entities. Xcel Energy implemented the guidance on Jan. 1, 2016, and other than the classification of certain real estate investments held within the Nuclear Decommissioning Trust as non-consolidated variable interest entities, the implementation did not have a significant impact on its consolidated financial statements.

Presentation of Debt Issuance Costs — In April 2015, the FASB issued Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30 (ASU No. 2015-03), which requires the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of presentation as an asset. Xcel Energy implemented the new guidance as required on Jan. 1, 2016, and as a result, $94.5 million of deferred debt issuance costs were presented as a deduction from the carrying amount of long-term debt on the consolidated balance sheet as of March 31, 2016, and $91.8 million of such deferred costs were retrospectively reclassified from other non-current assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

Fair Value Measurement — In May 2015, the FASB issued Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent), Topic 820 (ASU No. 2015-07), which eliminates the requirement to categorize fair value measurements using a net asset value (NAV) methodology in the fair value hierarchy. Xcel Energy implemented the guidance on Jan. 1, 2016, and the implementation did not have a material impact on its consolidated financial statements. For related disclosures, see Note 8 to the consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	June 30, 2016	Dec. 31, 2015
Accounts receivable, net		
Accounts receivable	$735,586	$776,494
Less allowance for bad debts	(46,022)	(51,888)
	$689,564	$724,606

(Thousands of Dollars)	June 30, 2016	Dec. 31, 2015
Inventories		
Materials and supplies	$304,055	$290,690

Fuel	164,054	202,271
Natural gas	58,676	115,623
	$526,785	$608,584

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(Thousands of Dollars)	June 30, 2016	Dec. 31, 2015
Property, plant and equipment, net		
Electric plant	$36,990,529	$36,464,050
Natural gas plant	5,065,218	4,944,757
Common and other property	1,746,789	1,709,508
Plant to be retired [(a)]	29,853	38,249
Construction work in progress	1,687,397	1,256,949
Total property, plant and equipment	45,519,786	44,413,513
Less accumulated depreciation	(14,035,591)	(13,591,259)
Nuclear fuel	2,461,008	2,447,251
Less accumulated amortization	(2,121,921)	(2,063,654)
	$31,823,282	$31,205,851

(a) In 2017, PSCo expects to both early retire Valmont Unit 5 and convert Cherokee Unit 4 from a coal-fueled generating facility to natural gas, as approved by the Colorado Public Utilities Commission (CPUC). Amounts are presented net of accumulated depreciation.

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, 2015 appropriately represents, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Tax Loss Carryback Claims — In 2012, 2013, 2014 and 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 Audit — Xcel Energy files a consolidated federal income tax return. In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of June 30, 2016, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $14 million of income tax expense for the 2009 through 2011 and 2013 claims, the recently filed 2014 claim, and the anticipated claim for 2015. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In the second quarter of 2016 the IRS audit team presented their case to Appeals; however, the outcome and timing of a resolution is uncertain. The statute of limitations applicable to Xcel Energy’s 2009 through 2011 federal income tax returns expires in December 2016 following an extension to allow additional time for the Appeals process. In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. As of June 30, 2016, the IRS had not proposed any material adjustments to tax years 2012 and 2013.

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 June 30, 2016, 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 2011

In February 2016, Texas began an audit of years 2009 and 2010. As of June 30, 2016, Texas had not proposed any adjustments.

In June 2016, Minnesota began an audit of years 2010 through 2014. As of June 30, 2016, Minnesota had not proposed any adjustments. As of June 30, 2016, there were no other state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (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.

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

(Millions of Dollars)	June 30, 2016	Dec. 31, 2015
Unrecognized tax benefit — Permanent tax positions	$ 26.8	$ 25.8
Unrecognized tax benefit — Temporary tax positions	97.6	94.9
Total unrecognized tax benefit	$ 124.4	$ 120.7

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

(Millions of Dollars)	June 30, 2016	Dec. 31, 2015
NOL and tax credit carryforwards	$ (40.4)	$ (36.7)

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 and audit progress, the Minnesota and Texas audits progress, and other state audits resume. As the IRS Appeals and IRS, Minnesota, and Texas audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $58 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at June 30, 2016 and Dec. 31, 2015 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2016 or Dec. 31, 2015.

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, 2015 and in Note 5 to Xcel Energy Inc.'s Quarterly Report on
Form 10-Q for the quarterly period ended March 31, 2016, 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 November 2015, NSP-Minnesota filed a three-year electric rate case with the MPUC. The rate case is based on a requested return on equity (ROE) of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below:

Request (Millions of Dollars)	2016	2017	2018
Rate request	$194.6	$52.1	$50.4
Increase percentage	6.4 %	1.7 %	1.7 %
Interim request	$163.7	$44.9	N/A
Rate base	$7,800	$7,700	$7,700

In December 2015, the MPUC approved interim rates for 2016.

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Intervenor Testimony:
In June 2016, intervening parties filed direct testimony proposing modifications to NSP-Minnesota's rate request. The Minnesota Department of Commerce (DOC) subsequently filed revised testimony recommending an increase of approximately $45.6 million in 2016, a step increase of $53.8 million for 2017, and a step decrease of $5.0 million for 2018, based on a recommended ROE of 9.06 percent and an equity ratio of 52.50 percent.

Based on NSP-Minnesota's interpretation of the DOC's testimony, certain recommended adjustments of approximately $72.7 million would not be expected to impact earnings, assuming MPUC approval. The following table summarizes NSP-Minnesota's estimate of the DOC's recommendations:

(Millions of Dollars)	2016	2017 Step	2018 Step	Total
Filed rate request	$194.6	$52.1	$50.4	$297.1
DOC recommended adjustments:				
ROE	(65.0)	0.3	1.0	(63.7)
Sales forecast	(39.4)	—	—	(39.4)
Property tax	(5.2)	(0.3)	(0.1)	(5.6)
Depreciation life	(8.0)	0.4	(2.2)	(9.8)
Purchased demand timing changes	—	—	(19.4)	(19.4)
Nuclear capital costs	(3.6)	0.8	(11.2)	(14.0)
Tax related items	(12.2)	18.4	(6.9)	(0.7)
Operating and maintenance (O&M)	(15.5)	(17.8)	(16.7)	(50.0)
Other, net	(0.1)	(0.1)	0.1	(0.1)
Total DOC Adjustments	(149.0)	1.7	(55.4)	(202.7)
Total DOC recommended rate increase	$45.6	$53.8	$(5.0)	$94.4
Estimated non-earnings DOC adjustments:				
Depreciation life	8.0	(0.4)	2.2	9.8
Sales forecast	37.4	—	—	37.4
Property tax	5.2	0.3	0.1	5.6
Purchased demand timing changes	—	—	19.4	19.4
Other	0.5	—	—	0.5
Total estimated non-earnings adjustments	51.1	(0.1)	21.7	72.7
Total pre-tax earnings impact	$96.7	$53.7	$16.7	$167.1

The DOC also presented several nuclear recommendations related to capital recovery for spent fuel storage investments and Prairie Island LCM projects.

- The use of certificate of need estimates as a recovery cap, and/or provisionally exclude recovery of amounts in excess of the cap unless the costs are deemed reasonable by the DOC's nuclear consultant and/or the MPUC.
- No recovery of a portion of capital costs associated with Monticello fuel storage Cask 16, representing the amount beyond the originally anticipated project cost, or approximately $15 million. The additional costs incurred were for testing of cask lid welds to demonstrate compliance with Nuclear Regulatory Commission requirements.

Settlement Agreement
In August 2016, NSP-Minnesota reached a settlement in principal with several of the parties, which resolves all revenue requirement issues in dispute. The terms and conditions of the agreement are still subject to final documentation. The settlement agreement requires the approval of the MPUC.

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The next steps in the procedural schedule are expected to be as follows:

- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- Administrative Law Judge report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

A current liability representing NSP-Minnesota's best estimate of a refund obligation for 2016 associated with interim rates was recorded as of June 30, 2016.

NSP-Minnesota – Gas Utility Infrastructure Costs (GUIC) Rider — In July 2016, the MPUC verbally approved NSP-Minnesota's request to recover approximately $15 million in natural gas infrastructure costs through the GUIC Rider, based on NSP-Minnesota's proposed capital structure and a ROE of 9.64 percent, as proposed by the DOC. Recovery was approved for the 15-month period from January 2016 to March 2017.

Annual Automatic Adjustment (AAA) of Charges — In June 2016, the DOC recommended the MPUC should hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages at nuclear facilities under certain circumstances. As it pertains to NSP-Minnesota, the DOC's recommendation could impact replacement power cost recovery for the Prairie Island (PI) nuclear facility outages allocated to the Minnesota jurisdiction during the 2015 AAA fiscal year. NSP-Minnesota expects a MPUC decision in mid-2017.

Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/extended power uprate (EPU) project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW) in 2015. The Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes allowance for funds used during construction (AFUDC). In 2008, project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent. In March 2015, the MPUC voted to allow for full recovery, including a return, on approximately $415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment over the remaining life of the plant. Further, the MPUC determined that only 50 percent of the investment was considered used-and-useful for 2014. As a result of these determinations, Xcel Energy recorded an estimated pre-tax loss of $129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

NSP-Wisconsin

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

Wisconsin 2017 Electric and Gas Rate Case — In April 2016, NSP-Wisconsin filed a request with the PSCW for an increase in annual electric rates of $17.4 million, or 2.4 percent, and an increase in natural gas rates by $4.8 million, or 3.9 percent, effective January 2017.

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The following table outlines the filed request:

Electric Rate Request (Millions of Dollars)	Request
Rate base investments	$ 11.0
Generation and transmission expenses (excluding fuel and purchased power)	6.8
Fuel and purchased power expenses	11.0
Subtotal	28.8
2015 fuel refund [a]	(9.5)
DOE settlement refund	(1.9)
Total electric rate increase	$ 17.4

(a) In July 2016, the PSCW required NSP-Wisconsin to return the 2015 fuel refund directly to customers, rather than using it to offset the proposed 2017 rate increase, as originally proposed by NSP-Wisconsin. This decision effectively increases NSP-Wisconsin's requested electric rate increase to $26.9 million, or 3.8 percent.

The electric rate request is for the limited purpose of recovering increases in (1) generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with NSP-Minnesota, and (2) costs associated with forecasted average rate base of $1.188 billion in 2017.

The natural gas rate request is for the limited purpose of recovering expenses related to the ongoing environmental remediation of a former manufactured gas plant (MGP) site and adjacent area in Ashland, Wis.

No changes are being requested to the capital structure or the 10.0 percent ROE authorized by the PSCW in the 2016 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap, solely for 2017, in which 100 percent of the earnings in excess of the authorized ROE would be refunded to customers.

Key dates in the procedural schedule are as follows:

- Staff and intervenor direct testimony — Aug. 12, 2016;
- Rebuttal testimony — Aug. 26, 2016;
- Surrebuttal testimony — Sept. 2, 2016;
- Hearing — Sept. 7, 2016;
- Initial brief due — Sept. 21, 2016;
- Reply brief due — Sept. 28, 2016; and
- A final PSCW decision is anticipated in the fourth quarter of 2016 with final rates effective in January 2017.

PSCo

Pending Regulatory Proceedings — CPUC

Annual Electric Earnings Tests — As part of an annual earnings test, PSCo must share with customers earnings that exceed the authorized ROE threshold of 9.83 percent for 2015 through 2017. In April 2016, PSCo filed the 2015 earnings test, proposing an electric customer refund obligation of $14.9 million, which was approved by the CPUC in July 2016. The proposed refund obligation related to the 2015 earnings test was accrued for as of June 30, 2016. The current estimate of the 2016 earnings test, based on annual forecasted information, did not result in the recognition of a liability as of June 30, 2016.

SPS

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

Appeal of the Texas 2015 Electric Rate Case Decision — 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.

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In 2014, SPS had requested an overall retail electric revenue rate increase of $64.8 million, which it subsequently revised to $42.1 million. In 2015, the PUCT approved an overall rate decrease of approximately $4.0 million, net of rate case expenses.

The hearing in the appeal is scheduled for February 2017.

Texas 2015 Electric Rate Net Refund Case — Under an agreement in the Texas 2015 electric rate case, the final rates were retroactively applied to June 11, 2015. In June 2016, SPS filed an application to provide a net refund of approximately $1.25 million to reflect the difference in revenue SPS would have received for usage had SPS been charging the final rates approved by the PUCT from June 11, 2015 through Jan. 31, 2016. SPS has proposed to make the net refund over a six-month period beginning October 2016. The application is pending before the PUCT.

Texas 2016 Electric Rate Case — In February 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the PUCT requesting an overall increase in annual base rate revenue of approximately $71.9 million, or 14.4 percent. The filing is based on a historic test year (HTY) ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately $1.7 billion, and an equity ratio of 53.97 percent. In April 2016, SPS revised its requested rate increase to $68.6 million.

The following table summarizes the revised net request:

(Millions of Dollars)	Request
Capital expenditure investments	$ 38.9
Change in jurisdictional allocation factors	9.8
Changes in ROE and capital structure	11.6
Estimated rate case expenses	4.5
Other, net	3.8
Total	$ 68.6

Key dates in the procedural schedule are as follows:

- Intervenor direct testimony — Aug. 16, 2016;
- PUCT Staff direct testimony — Aug. 23, 2016;
- PUCT Staff and Intervenors' cross-rebuttal testimony — Sept. 7, 2016;
- SPS' rebuttal testimony — Sept. 9, 2016; and
- Hearings — Sept. 27 - Oct. 7, 2016.

SPS and various parties are having discussions regarding a potential settlement of the rate case. The final rates established at the end of the case are expected to be effective retroactive to July 20, 2016. A PUCT decision is expected in the first quarter of 2017.

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

New Mexico 2015 Electric Rate Case — In October 2015, SPS filed an electric rate case with the NMPRC seeking an increase in non-fuel base rates of $45.4 million. The proposed increase would be offset by a decrease in base fuel revenue of approximately $21.1 million. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric rate base of approximately $734 million and an equity ratio of 53.97 percent.

In May 2016, SPS, the NMPRC Staff and all other parties filed a unanimous black-box stipulation that resolves all issues in the case. Under the stipulation, SPS will implement a non-fuel base rate increase of $23.5 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power cost adjustment clause. The stipulation places no restriction on when SPS may file its next base rate case.

In July 2016, the hearing examiner issued a recommendation that the NMPRC approve the stipulation. The stipulation is subject to approval by the NMPRC and a decision on the settlement and implementation of final rates is expected in fall of 2016.

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Pending Regulatory Proceedings — FERC

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaints/ROE Adder — 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, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for regional transmission organization (RTO) membership and being an independent transmission company), effective Nov. 12, 2013.

In December 2015, an ALJ initial decision recommended the FERC approve a ROE of 10.32 percent. A FERC order is expected to be issued in late 2016 or in 2017.

In February 2015, a second complaint was filed seeking to reduce the MISO region ROE from 12.38 percent to 8.67 percent, prior to any adder. The FERC set the second complaint for hearings, and established a refund effective date of Feb. 12, 2015. The MPUC, the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission and the DOC joined a joint complainant/intervenor initial brief recommending an ROE of either 8.82 percent or 8.81 percent. FERC staff recommended a ROE of 8.78 percent. The MISO TOs recommended a ROE of 10.92 percent. On June 30, 2016, the ALJ issued an initial decision recommending a ROE of 9.7 percent, the midpoint of the upper half of the discounted cash flow (DCF) range, with refunds for the 15 month period beginning Feb.12, 2015. A FERC decision is expected in 2017.

FERC approved of a 50 basis point ROE adder for RTO membership, effective Jan. 6, 2015, subject to the outcome of the ROE complaint. Under FERC policy, the total ROE including the RTO membership adder cannot exceed the top of the DCF range.

NSP-Minnesota has recorded a current liability representing the best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of June 30, 2016. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between $8 million and $10 million, annually, for the NSP System.

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, in part, from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to collect charges since 2008, but to date SPP has not charged its customers any amounts attributable to these upgrades.

In April 2016, SPP filed a request with the FERC for a waiver that would allow SPP to recover the charges not billed since 2008. The FERC approved the waiver request in July 2016. SPS is considering whether to seek clarification or rehearing of the FERC order. SPP has indicated it anticipates completing its process and invoicing customers during the fourth quarter of 2016. SPS estimates the charges to be $5 million to $10 million, based on preliminary information. SPS anticipates these costs would be recoverable through regulatory mechanisms.

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, 2015, and in Notes 5 and 6 to the consolidated financial statements included in Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016, 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.

Purchased Power Agreements (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 3,467 MW and 3,698 MW of capacity under long-term PPAs as of June 30, 2016 and Dec. 31, 2015, 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 2033.

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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 limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of June 30, 2016 and Dec. 31, 2015, 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)	June 30, 2016	Dec. 31, 2015
Guarantees issued and outstanding	$ 15.9	$ 12.5
Current exposure under these guarantees	0.1	0.1
Bonds with indemnity protection	43.0	41.3

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 potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

Ashland MGP Site — NSP-Wisconsin has been 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 property owned by NSP-Wisconsin, 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 (the Sediments).

In 2010, the United States Environmental Protection Agency (EPA) issued its Record of Decision (ROD), including their preferred remedy for the Sediments which is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). A wet conventional dredging only remedy (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study, is another potential remedy.

In 2012, under a settlement agreement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site). The excavation and containment remedies are complete, and a long-term groundwater pump and treatment program is now underway. The final design was approved by the EPA in 2015. The current cost estimate for the cleanup of the Phase I Project Area is approximately $71.4 million, of which approximately $51.8 million has already been spent.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and which remedy will be implemented. The EPA's ROD includes estimates that the cost of the Hybrid

Remedy is between $63 million and $77 million, with a potential deviation in such estimated costs of up to 50 percent higher or 30 percent lower. NSP-Wisconsin believes the Hybrid Remedy is not safe or feasible to implement. In 2015, NSP-Wisconsin constructed a breakwater at the site to serve as wave attenuation and containment for a wet dredge pilot study and full scale sediment remedy at the site. Equipment mobilization for the wet dredge pilot study commenced in April 2016. The pilot study is expected to conclude in late summer of 2016. The EPA will then determine whether NSP-Wisconsin can perform extended pilot work into early fall of 2016 and whether a full scale wet dredge remedy of the Sediments may be performed beginning as early as 2017.

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At June 30, 2016 and Dec. 31, 2015, NSP-Wisconsin had recorded a liability of $95.0 million and $94.4 million, respectively, for the Site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $18.7 million and $17.0 million, respectively, were considered a current liability. NSP-Wisconsin’s potential liability, the actual cost of remediation and the timing of expenditures are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the remediation cost of the entire site.

NSP-Wisconsin has deferred the estimated site remediation costs as a regulatory asset. The PSCW has consistently authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In a December 2012 decision, 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 April 2016, NSP-Wisconsin filed a limited natural gas rate case for recovering additional expenses associated with remediating the Site. If approved, the annual recovery of MGP clean-up costs would increase from $7.6 million in 2016 to $12.4 million in 2017.

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in Fargo, N.D., which may be related to a former MGP site operated by NSP-Minnesota or a prior company. NSP-Minnesota has removed the impacted soils and other materials from the project area. NSP-Minnesota is undertaking further investigation of the location of the historic MGP site and nearby properties. In October 2015, NSP-Minnesota 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 November 2016 to allow NSP-Minnesota time to further investigate site conditions.

As of June 30, 2016 and Dec. 31, 2015, NSP-Minnesota had recorded a liability of $1.6 million and $2.7 million, respectively, related to further investigation and additional planned activities. Uncertainties include the nature and cost of the additional remediation efforts that may be necessary, the ability to recover costs from insurance carriers and the potential for contributions from entities that may be identified as PRPs. Therefore, the total cost of remediation, NSP-Minnesota’s potential liability and amounts allocable to the North Dakota and Minnesota jurisdictions related to the site cannot currently be reasonably estimated. In December 2015, the NDPSC approved NSP-Minnesota’s request to defer the portion of investigation and response costs allocable to the North Dakota jurisdiction.

Environmental Requirements

Water and Waste

Coal Ash Regulation — Xcel Energy’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In April 2015, the EPA published a final rule regulating the management and disposal of coal combustion byproducts (coal ash) as a nonhazardous waste. Under the final rule, Xcel Energy’s costs to manage and dispose of coal ash has not significantly increased.

In 2015, industry and environmental non-governmental organizations sought judicial review of the final rule. In June 2016, the D.C Circuit issued an order remanding and vacating certain elements of the rule as a result of partial settlements with these parties. Oral arguments are expected to be heard in the second half of 2016 and a final decision is anticipated in early 2017. Until a final decision is reached in the case, it is uncertain whether the litigation or partial settlements will have any significant impact on results of operations, financial position or cash flows on Xcel Energy.

Air

Regional Haze Rules — The regional haze program is designed to address widespread haze that results from emissions from a multitude of sources. In 2005, the EPA amended the best available retrofit technology (BART) requirements of its regional haze rules, which 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 (PM) 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).

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Texas developed a state implementation plan (SIP) that finds the CAIR equal to BART for electric generating units (EGUs). As a result, no additional controls beyond CAIR compliance would be required. In December 2014, the EPA proposed to approve the BART portion of the SIP, with the exception that the EPA would substitute the CSAPR compliance for Texas' reliance on CAIR. In January 2016, the EPA adopted a final rule that defers its approval of CSAPR compliance as BART until the EPA considers further adjustments to CSAPR emission budgets under the United States Court of Appeals for the District of Columbia Circuit's (D.C. Circuit) remand of the Texas SO_2 emission budgets. In March 2016, the EPA requested information under the Clean Air Act (CAA) related to EGUs at SPS' plants. SPS identified Harrington Units 1 and 2, Jones Units 1 and 2, Nichols Unit 3 and Plant X Unit 4 as BART-eligible units. These units will be evaluated based on their impact on visibility. Additional emission control equipment under the EPA's BART guidelines for PM, SO_2 and NOx could be required if a unit is determined to "cause or contribute" to visibility impairment. SPS cannot evaluate the impact of additional emission controls until the EPA concludes its evaluation of BART. The EPA is expected to issue a proposed rule in December 2016. In June 2016, the EPA issued a memorandum which allows Texas to voluntarily adopt the CSAPR emission budgets limiting annual SO_2 and NOx emissions and rely on those emission budgets to satisfy Texas' BART obligations under the regional haze rules. It is not yet known whether the Texas Commission on Environmental Quality (TCEQ) intends to utilize this option.

In December 2014, the EPA proposed to disapprove the reasonable progress portions of the SIP and instead adopt a federal implementation plan (FIP). In January 2016, the EPA adopted a final rule establishing a FIP for the state of Texas. As part of this final rule, the EPA 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. In March 2016, SPS appealed the EPA's decision and asked for a stay of the final rule while it is being reviewed. In July 2016, the United States Court of Appeals for the Fifth Circuit (Fifth Circuit) granted the stay motion and decided that the Fifth Circuit, not the D.C. Circuit, is the appropriate venue for this case. In addition, SPS filed a petition with the EPA requesting reconsideration of the final rule. SPS believes these costs would be recoverable through regulatory mechanisms if required, and therefore does not expect a material impact on results of operations, financial position or cash flows.

Implementation of the National Ambient Air Quality Standard (NAAQS) for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. The EPA is requiring states to evaluate areas in three phases. The first phase includes areas near PSCo's Pawnee plant and SPS' Tolk and Harrington plants. The Pawnee plant recently installed an SO_2 scrubber and the Tolk and Harrington Plants utilize low sulfur coal to reduce SO_2 emissions. In June 2016, the EPA issued final designations which found the area near the Tolk plant to be meeting the NAAQS and the areas near the Harrington and Pawnee plants as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020. It is anticipated that the area near the Pawnee plant will be able to show compliance with the NAAQS through air dispersion modeling performed by the Colorado Department of Public Health and Environment.

If an area is designated nonattainment in 2020, the respective states will need to evaluate all SO_2 sources in the area. The state would then submit an implementation plan, which would be due by 2022, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. The areas near the remaining Xcel Energy power plants will be evaluated in the next designation phase, ending December 2017. The remaining plants, PSCo's Comanche and Hayden plants along with NSP-Minnesota's King and Sherco plants, utilize scrubbers to control SO_2 emissions. Xcel Energy cannot evaluate the impacts until the designation of nonattainment areas is made and any required state plans are developed. Xcel Energy believes that, should SO_2 control systems be required for a plant, compliance costs will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial position or cash flows.

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.

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Employment, Tort and Commercial Litigation

Pacific Northwest FERC Refund Proceeding — A complaint with the FERC posed that sales made in the Pacific Northwest in 2000 and 2001 through bilateral contracts were unjust and unreasonable under the Federal Power Act. The City of Seattle (the City) alleges between $34 million to $50 million in sales with PSCo is subject to refund. In 2003, the FERC terminated the proceeding, although it was later remanded back to the FERC in 2007 by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2015, in the remand proceeding, the FERC issued an order rejecting the City's claim that any of the sales made resulted in an excessive burden and concluded that the City failed to establish a causal link between any contracts and any claimed unlawful market activity. In February 2016, the City appealed this decision to the Ninth Circuit. This appeal is pending review by the Ninth Circuit.

Also in December 2015, the Ninth Circuit issued an order and held that the standard of review applied by the FERC to the contracts which the City was challenging is appropriate. The Ninth Circuit dismissed questions concerning whether the FERC properly established the scope of the hearing, and determined that the challenged orders are preliminary and that the Ninth Circuit lacks jurisdiction to review evidentiary decisions until after the FERC's proceedings are final. The City joined the State of California in its request seeking rehearing of this order, which the Ninth Circuit denied.

Preliminary calculations of the City's claim for refunds from PSCo are approximately $28 million, excluding interest, or approximately $60 million, including interest. PSCo has concluded that a loss is reasonably possible; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

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. Five of the cases have since been settled and seven have been dismissed. One multi-district litigation (MDL) matter remains and it consists of a Colorado class (Breckenridge), a Wisconsin class (NSP-Wisconsin), a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." In May 2016, the MDL judge granted summary judgment dismissing defendants from the Farmland lawsuit. e prime and Xcel Energy have filed a motion seeking clarification that this order includes them. This motion is currently pending. The e prime defendants recently filed a summary judgment motion in the Colorado class lawsuit (Breckenridge) and oppositions to class certifications in all the class actions. Trial dates have not yet been set, but are not expected to occur prior to early 2017. 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 service agreements entered into by PSCo and various developers. The dispute involves assigned interests in those 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 filed a notice of appeal. 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.

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.

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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 June 30, 2016	Year Ended Dec. 31, 2015
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	447	846
Average amount outstanding	404	601
Maximum amount outstanding	841	1,360
Weighted average interest rate, computed on a daily basis	0.72 %	0.48 %
Weighted average interest rate at period end	0.80	0.82

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 June 30, 2016 and Dec. 31, 2015, there were $28 million and $29 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, Xcel Energy Inc. and its utility subsidiaries must have credit facilities in place at least equal to the amount of their commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available credit facility capacity. 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.

At June 30, 2016, 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	$ 414	$ 586
PSCo	700	3	697
NSP-Minnesota	500	18	482
SPS	400	32	368
NSP-Wisconsin	150	8	142
Total	$ 2,750	$ 475	$ 2,275

(a) These credit facilities expire in June 2021.

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

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 at June 30, 2016 and Dec. 31, 2015.

Amended Credit Agreements - In June 2016, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements remained at $2.75 billion. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the following exceptions:

- The maturity extended from October 2019 to June 2021.
-

- The Eurodollar borrowing margins on these lines of credit were reduced to a range of 75 to 150 basis points per year, from a range of 87.5 to 175 basis points per year, based upon applicable long-term credit ratings.
- The commitment fees, calculated on the unused portion of the lines of credit, were reduced to a range of 6 to 22.5 basis points per year, from a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS 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.

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Long-Term Borrowings

During the six months ended June 30, 2016, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046; and
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046.

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 prices.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using a net asset value (NAV) methodology, which takes 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 and international equity 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.

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

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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. 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, 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 energy congestion, which is caused by transmission load and transmission constraints. Congestion is also influenced by the operating schedules of power plants and the consumption of electricity. Unplanned plant outages, scheduled plant maintenance, changes in the costs of fuels used in generation, weather and changes in demand for electricity can each impact the operating schedules of the power plants and the value of an FTR. The valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

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 observability of management's forecasts for several of the inputs to this complex valuation model fair value measurements for FTRs have been assigned a Level 3. Monthly settlements for non-trading FTRs 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 relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

Nuclear Decommissioning Fund

The 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 purpose of 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. 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, given the purpose and legal restrictions on the use of nuclear decommissioning fund assets. 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 $336.5 million and $328.8 million at June 30, 2016 and Dec. 31, 2015, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were

$95.2 million and $100.2 million at June 30, 2016 and Dec. 31, 2015, respectively.

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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 at June 30, 2016 and Dec. 31, 2015:

	June 30, 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	$15,749	$15,749	$—	$ —	$ —	$15,749
Commingled funds	389,700	—	—	—	411,788	411,788
International equity funds	259,090	—	—	—	236,087	236,087
Private equity investments	119,370	—	—	—	166,054	166,054
Real estate	72,956	—	—	—	102,144	102,144
Debt securities:						
Government securities	35,199	—	35,828	—	—	35,828
U.S. corporate bonds	96,110	—	91,350	—	—	91,350
International corporate bonds	19,959	—	19,394	—	—	19,394
Municipal bonds	11,966	—	12,826	—	—	12,826
Asset-backed securities	2,844	—	2,881	—	—	2,881
Mortgage-backed securities	10,708	—	11,180	—	—	11,180
Equity securities:						
Common stock	479,865	649,521	—	—	—	649,521
Total	$1,513,516	$665,270	$173,459	$ —	$ 916,073	$1,754,802

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $133.7 million of equity investments in unconsolidated subsidiaries and $99.0 million of rabbi trust assets and miscellaneous investments.

(b) Based on the requirements of ASU 2015-07, investments measured at fair value using a NAV methodology have not been classified in the fair value hierarchy. See Note 2 for further information on the adoption of ASU 2015-07.

	Dec. 31, 2015					
		Fair Value				
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [b]	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$27,484	$27,484	$—	$ —	$ —	$27,484
Commingled funds	392,838	—	—	—	410,634	410,634
International equity funds	259,114	—	—	—	231,122	231,122
Private equity investments	105,965	—	—	—	157,528	157,528
Real estate	61,816	—	—	—	84,750	84,750
Debt securities:						
Government securities	24,444	—	21,356	—	—	21,356
U.S. corporate bonds	73,061	—	65,276	—	—	65,276
International corporate bonds	13,726	—	12,801	—	—	12,801
Municipal bonds	49,255	—	51,589	—	—	51,589
Asset-backed securities	2,837	—	2,830	—	—	2,830
Mortgage-backed securities	11,444	—	11,621	—	—	11,621
Equity securities:						
Common stock	473,615	647,159	—	—	—	647,159

Total	$1,495,599	$674,643	$165,473	$ —	$884,034	$1,724,150

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $130.0 million of equity investments in unconsolidated subsidiaries and $48.9 million of miscellaneous investments.

(b) Based on the requirements of ASU 2015-07, investments measured at fair value using a NAV methodology have not been classified in the fair value hierarchy. See Note 2 for further information on the adoption of ASU 2015-07.

For the six months ended June 30, 2016 and 2015 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

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The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at June 30, 2016:

	Final Contractual Maturity				
(Thousands of Dollars)	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	$—	$10,659	$982	$24,187	$35,828
U.S. corporate bonds	261	26,988	59,368	4,733	91,350
International corporate bonds	—	3,966	12,368	3,060	19,394
Municipal bonds	—	212	4,248	8,366	12,826
Asset-backed securities	—	—	2,881	—	2,881
Mortgage-backed securities	—	—	—	11,180	11,180
Debt securities	$261	$41,825	$79,847	$51,526	$173,459

Rabbi Trusts

In June 2016, Xcel Energy established rabbi trusts to provide funding for future distributions of its supplemental executive retirement plan and nonqualified pension plans. The following table presents the cost and fair value of the assets held in rabbi trusts at June 30, 2016:

	June 30, 2016				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$47,762	$47,762	$ —	$ —	$47,762
Mutual funds	1,593	1,778	—	—	1,778
Total	$49,355	$49,540	$ —	$ —	$49,540

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

An immaterial amount of mutual funds were held in rabbi trusts at Dec. 31, 2015.

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.

At June 30, 2016, accumulated other comprehensive losses related to interest rate derivatives included $3.4 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 and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

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.

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At June 30, 2016, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not 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 six months ended June 30, 2016 and 2015.

At June 30, 2016, net losses related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net losses 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 at June 30, 2016 and Dec. 31, 2015:

(Amounts in Thousands) [a][b]	June 30, 2016	Dec. 31, 2015
Megawatt hours of electricity	81,667	50,487
Million British thermal units of natural gas	84,578	20,874
Gallons of vehicle fuel	70	141

[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.

The following tables detail the impact of derivative activity during the three and six months ended June 30, 2016 and 2015, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended June 30, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains 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	$—	$ —	$1,483 [a]	$ —	$ —
Vehicle fuel and other commodity	19	—	47 [b]	—	—
Total	$19	$ —	$1,530	$ —	$ —
Other derivative instruments					
Commodity trading	$—	$ —	$—	$ —	$ 481 [c]
Electric commodity	—	(705)	—	16,642 [d]	—
Natural gas commodity	—	6,063	—	—	25 [e]

Total	$—	$ 5,358	$—	$ 16,642	$ 506

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	Six Months Ended June 30, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	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	$—	$ —	$2,968 [a]	$ —	$ —
Vehicle fuel and other commodity	13	—	104 [b]	—	—
Total	$13	$ —	$3,072	$ —	$ —
Other derivative instruments					
Commodity trading	$—	$ —	$—	$ —	$ 1,490 [c]
Electric commodity	—	(970)	—	27,533 [d]	—
Natural gas commodity	—	3,361	—	11,666 [e]	(4,999) [e]
Total	$—	$ 2,391	$—	$ 39,199	$ (3,509)

	Three Months Ended June 30, 2015				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$—	$ —	$954 [a]	$ —	$ —
Vehicle fuel and other commodity	29	—	28 [b]	—	—
Total	$29	$ —	$982	$ —	$ —
Other derivative instruments					
Commodity trading	$—	$ —	$—	$ —	$ 4,401 [c]
Electric commodity	—	(4,737)	—	(8,037) [d]	—
Natural gas commodity	—	(232)	—	(22) [e]	—
Total	$—	$ (4,969)	$—	$ (8,059)	$ 4,401

	Six Months Ended June 30, 2015				
	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	$—	$—	$1,894 [(a)]	$—	$ —
Vehicle fuel and other commodity	11	—	55 [(b)]	—	—
Total	$11	$—	$1,949	$—	$ —
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$ 8,281 [(c)]
Electric commodity	—	(14,208)	—	(13,160) [(d)]	—
Natural gas commodity	—	(448)	—	(8,852) [(e)]	8,991 [(e)]
Total	$—	$(14,656)	$—	$(22,012)	$ 17,272

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to 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 gain and loss amounts 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) Amounts for the three and six months ended June 30, 2016 and 2015 included an immaterial amount of settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. The remaining derivative settlement gains and losses for the three and six months ended June 30, 2016 and 2015 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 mechanisms and reclassified out of income to a regulatory asset or liability, as appropriate.

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Xcel Energy had no derivative instruments designated as fair value hedges during the three and six months ended June 30, 2016 and 2015. 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 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. 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 considering 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, 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.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At June 30, 2016, one of Xcel Energy's 10 most significant counterparties for these activities, comprising $13.5 million or 6 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Ratings Services, Moody's Investor Services or Fitch Ratings. Seven of the 10 most significant counterparties, comprising $55.6 million or 25 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 remaining two most significant counterparties, comprising $12.2 million or 6 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external and internal analysis. Nine of these significant counterparties are RTOs, municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as 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 is unable to maintain its credit ratings. At June 30, 2016 and Dec. 31, 2015, there were no derivative instruments in a liability position that would have required the posting of collateral or settlement of applicable outstanding contracts if the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade.

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 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 June 30, 2016 and Dec. 31, 2015.

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 at June 30, 2016:

	June 30, 2016					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [(b)]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$5,384	$14,675	$—	$20,059	$ (14,017)	$6,042
Electric commodity	—	—	28,151	28,151	(3,593)	24,558

Natural gas commodity	—	8,525	—	8,525	(31	) 8,494
Total current derivative assets	$5,384	$23,200	$28,151	$56,735	$ (17,641	) 39,094
PPAs [(a)]						7,859
Current derivative instruments						$46,953
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$1,037	$28,058	$—	$29,095	$ (6,986	) $22,109
Natural gas commodity	—	1,355	—	1,355	—	1,355
Total noncurrent derivative assets	$1,037	$29,413	$—	$30,450	$ (6,986	) 23,464
PPAs [(a)]						27,180
Noncurrent derivative instruments						$50,644

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(Thousands of Dollars)	June 30, 2016 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$82	$—	$82	$ —	$82
Other derivative instruments:						
Commodity trading	5,407	12,740	41	18,188	(14,575)	3,613
Electric commodity	—	—	3,593	3,593	(3,593)	—
Natural gas commodity	—	31	—	31	(31)	—
Total current derivative liabilities	$5,407	$12,853	$3,634	$21,894	$ (18,199)	3,695
PPAs [a]						22,847
Current derivative instruments						$26,542
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$1,086	$19,786	$—	$20,872	$ (11,162)	$9,710
Total noncurrent derivative liabilities	$1,086	$19,786	$—	$20,872	$ (11,162)	9,710
PPAs [a]						146,647
Noncurrent derivative instruments						$156,357

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. 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 June 30, 2016. At June 30, 2016, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $4.7 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 for each of the fair value hierarchy levels, Xcel Energy’s derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2015:

(Thousands of Dollars)	Dec. 31, 2015 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$225	$10,620	$1,250	$12,095	$ (5,865)	$6,230
Electric commodity	—	—	21,421	21,421	(4,088)	17,333
Natural gas commodity	—	496	—	496	(303)	193
Total current derivative assets	$225	$11,116	$22,671	$34,012	$ (10,256)	23,756
PPAs [a]						10,086
Current derivative instruments						$33,842

Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$27,416	$—	$27,416	$ (6,555)	$20,861
Total noncurrent derivative assets	$—	$27,416	$—	$27,416	$ (6,555)	20,861
PPAs [(a)]						30,222
Noncurrent derivative instruments						$51,083

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(Thousands of Dollars)	Dec. 31, 2015 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$205	$—	$205	$ —	$205
Other derivative instruments:						
Commodity trading	152	7,866	555	8,573	(6,904)	1,669
Electric commodity	—	—	4,088	4,088	(4,088)	—
Natural gas commodity	—	5,407	—	5,407	(303)	5,104
Total current derivative liabilities	$152	$13,478	$4,643	$18,273	$ (11,295)	6,978
PPAs [a]						22,861
Current derivative instruments						$29,839
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$19,898	$—	$19,898	$ (9,780)	$10,118
Total noncurrent derivative liabilities	$—	$19,898	$—	$19,898	$ (9,780)	10,118
PPAs [a]						158,193
Noncurrent derivative instruments						$168,311

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. 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, 2015. At Dec. 31, 2015, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $4.3 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 six months ended June 30, 2016 and 2015:

(Thousands of Dollars)	Three Months Ended June 30 2016	2015
Balance at April 1	$6,854	$17,429
Purchases	29,826	57,446
Settlements	(14,111)	(17,315)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [a]	(18)	1,220
Gains (losses) recognized as regulatory assets and liabilities	1,966	(11,953)
Balance at June 30	$24,517	$46,827

(Thousands of Dollars)	Six Months Ended June 30 2016	2015
Balance at Jan. 1	$18,028	$56,155
Purchases	31,670	63,238
Settlements	(26,161)	(37,246)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [(a)]	(43)	1,280
Gains (losses) recognized as regulatory assets and liabilities	1,023	(36,600)
Balance at June 30	$24,517	$46,827

(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 six months ended June 30, 2016 and 2015.

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Fair Value of Long-Term Debt

As of June 30, 2016 and Dec. 31, 2015, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	June 30, 2016 Carrying Amount	June 30, 2016 Fair Value	Dec. 31, 2015 Carrying Amount	Dec. 31, 2015 Fair Value
Long-term debt, including current portion [(a)]	$13,814,921	$15,935,100	$13,055,901	$14,094,744

(a) Amounts reflect the classification of debt issuance costs as a deduction from the carrying amount of the related debt. See Note 2, Accounting Pronouncements for more information on the adoption of ASU 2015-03.

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 June 30, 2016 and Dec. 31, 2015, 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 June 30		Six Months Ended June 30	
(Thousands of Dollars)	2016	2015	2016	2015
Interest income	$984	$389	$5,054	$4,627
Other nonoperating income	1,496	794	2,176	1,762
Insurance policy expense	(920)	(222)	(1,420)	(2,267)
Other income, net	$1,560	$961	$5,810	$4,122

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 $133.7 million and $130.0 million as of June 30, 2016 and Dec. 31, 2015, 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.

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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 June 30, 2016					
Operating revenues from external customers	$2,224,142	$258,899	$16,808	$ —	$2,499,849
Intersegment revenues	421	241	—	(662)	—
Total revenues	$2,224,563	$259,140	$16,808	$ (662)	$2,499,849
Net income (loss)	$205,440	$11,933	$(20,578)	$ —	$196,795

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2015					
Operating revenues from external customers	$2,213,460	$284,131	$17,543	$ —	$2,515,134
Intersegment revenues	420	172	—	(592)	—
Total revenues	$2,213,880	$284,303	$17,543	$ (592)	$2,515,134
Net income (loss)	$214,955	$(6,883)	$(11,141)	$ —	$196,931

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2016					
Operating revenues from external customers	$4,409,261	$824,588	$38,273	$ —	$5,272,122
Intersegment revenues	756	528	—	(1,284)	—
Total revenues	$4,410,017	$825,116	$38,273	$ (1,284)	$5,272,122
Net income (loss)	$383,677	$90,271	$(35,841)	$ —	$438,107

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2015					
Operating revenues from external customers	$4,438,323	$1,000,127	$38,903	$ —	$5,477,353
Intersegment revenues	750	848	—	(1,598)	—
Total revenues	$4,439,073	$1,000,975	$38,903	$ (1,598)	$5,477,353
Net income (loss)	$295,976 [a]	$76,793	$(23,772)	$ —	$348,997

[a] Includes a net of tax charge related to the Monticello LCM/EPU project. See Note 5.

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 dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants.

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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.

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 June 30, 2016			Three Months Ended June 30, 2015		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$196,795	—	—	$196,931	—	—
Basic EPS:						
Earnings available to common shareholders	196,795	508,930	$ 0.39	196,931	507,707	$ 0.39
Effect of dilutive securities:						
Time based equity awards	—	560	—	—	367	—
Diluted EPS:						
Earnings available to common shareholders	$196,795	509,490	$ 0.39	$196,931	508,074	$ 0.39

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$438,107	—	—	$348,997	—	—
Basic EPS:						
Earnings available to common shareholders	438,107	508,789	$ 0.86	348,997	507,359	$ 0.69
Effect of dilutive securities:						
Time based equity awards	—	522	—	—	388	—
Diluted EPS:						
Earnings available to common shareholders	$438,107	509,311	$ 0.86	$348,997	507,747	$ 0.69

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2016	2015	2016	2015
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$22,945	$24,828	$431	$529

Interest cost	40,028	37,131	6,526	6,324
Expected return on plan assets	(52,575)	(53,472)	(6,248)	(6,650)
Amortization of prior service credit	(477)	(451)	(2,671)	(2,671)
Amortization of net loss	24,385	31,288	1,009	1,351
Net periodic benefit cost (credit)	34,306	39,324	(953)	(1,117)
Costs not recognized due to the effects of regulation	(4,159)	(7,523)	—	—
Net benefit cost (credit) recognized for financial reporting	$30,147	$31,801	$(953)	$(1,117)

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	Six Months Ended June 30			
	2016	2015	2016	2015
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$45,865	$49,656	$863	$1,058
Interest cost	80,051	74,262	13,053	12,648
Expected return on plan assets	(105,150)	(106,945)	(12,497)	(13,300)
Amortization of prior service credit	(961)	(902)	(5,343)	(5,343)
Amortization of net loss	48,770	62,576	2,020	2,702
Net periodic benefit cost (credit)	68,575	78,647	(1,904)	(2,235)
Costs not recognized due to the effects of regulation	(8,611)	(15,019)	—	—
Net benefit cost (credit) recognized for financial reporting	$59,964	$63,628	$(1,904)	$(2,235)

In January 2016, contributions of $125.0 million were made across four of Xcel Energy’s pension plans. Xcel Energy does not expect additional pension contributions during 2016.

13. Other Comprehensive Income

Changes in accumulated other comprehensive (loss) income, net of tax, for the three and six months ended June 30, 2016 and 2015 were as follows:

	Three Months Ended June 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 April 1	$(53,928)	$ 110	$ (54,790)	$(108,608)
Other comprehensive income before reclassifications	12	—	—	12
Losses reclassified from net accumulated other comprehensive loss	936	—	865	1,801
Net current period other comprehensive income	948	—	865	1,813
Accumulated other comprehensive (loss) income at June 30	$(52,980)	$ 110	$ (53,925)	$(106,795)

	Three Months Ended June 30, 2015			
(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 April 1	$(57,054)	$ 111	$ (49,745)	$(106,688)
Other comprehensive income before reclassifications	18	1	—	19
Losses reclassified from net accumulated other comprehensive loss	600	—	883	1,483
Net current period other comprehensive income	618	1	883	1,502
Accumulated other comprehensive (loss) income at June 30	$(56,436)	$ 112	$ (48,862)	$(105,186)

	Six Months Ended June 30, 2016			
(Thousands of Dollars)	Gains and Losses on Cash Flow	Unrealized Gains and Losses	Defined Benefit Pension and	Total

	Hedges	on Marketable Securities	Postretirement Items	
Accumulated other comprehensive (loss) income at Jan. 1	$(54,862)	$ 110	$ (55,001)	$(109,753)
Other comprehensive income (loss) before reclassifications	8	—	(653)	(645)
Losses reclassified from net accumulated other comprehensive loss	1,874	—	1,729	3,603
Net current period other comprehensive income	1,882	—	1,076	2,958
Accumulated other comprehensive (loss) income at June 30	$(52,980)	$ 110	$ (53,925)	$(106,795)

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(Thousands of Dollars)	Six Months Ended June 30, 2015 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 Jan. 1	$ (57,628)	$ 110	$ (50,621)	$ (108,139)
Other comprehensive income before reclassifications	7	2	—	9
Losses reclassified from net accumulated other comprehensive loss	1,185	—	1,759	2,944
Net current period other comprehensive income	1,192	2	1,759	2,953
Accumulated other comprehensive (loss) income at June 30	$ (56,436)	$ 112	$ (48,862)	$ (105,186)

Reclassifications from accumulated other comprehensive loss for the three and six months ended June 30, 2016 and 2015 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended June 30, 2016	Three Months Ended June 30, 2015
(Gains) losses on cash flow hedges:		
Interest rate derivatives	$ 1,483 (a)	$ 954 (a)
Vehicle fuel derivatives	47 (b)	28 (b)
Total, pre-tax	1,530	982
Tax benefit	(594)	(382)
Total, net of tax	936	600
Defined benefit pension and postretirement (gains) losses:		
Amortization of net loss	1,478 (c)	1,533 (c)
Prior service credit	(64) (c)	(89) (c)
Total, pre-tax	1,414	1,444
Tax benefit	(549)	(561)
Total, net of tax	865	883
Total amounts reclassified, net of tax	$ 1,801	$ 1,483

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Six Months Ended June 30,	Six Months Ended June 30,

	2016		2015	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$ 2,968	(a)	$ 1,894	(a)
Vehicle fuel derivatives	104	(b)	55	(b)
Total, pre-tax	3,072		1,949	
Tax benefit	(1,198	)	(764	)
Total, net of tax	1,874		1,185	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	2,956	(c)	3,068	(c)
Prior service credit	(128	) (c)	(179	) (c)
Total, pre-tax	2,828		2,889	
Tax benefit	(1,099	)	(1,130	)
Total, net of tax	1,729		1,759	
Total amounts reclassified, net of tax	$ 3,603		$ 2,944	

(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.

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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 2016 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," "potential, 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, 2015 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2016), 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 of 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.

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Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	2016	2015	2016	2015
PSCo	$0.17	$0.19	$0.40	$0.41
NSP-Minnesota	0.15	0.15	0.34	0.32
SPS	0.06	0.05	0.11	0.08
NSP-Wisconsin	0.02	0.02	0.06	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.02
Regulated utility [a]	0.42	0.42	0.93	0.90
Xcel Energy Inc. and other	(0.04)	(0.03)	(0.07)	(0.05)
Ongoing diluted EPS [a]	0.39	0.39	0.86	0.85
Loss on Monticello LCM/EPU project	—	—	—	(0.16)
GAAP diluted EPS	$0.39	$0.39	$0.86	$0.69

[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.

For the six months ended June 30, 2015, GAAP earnings included a $0.16 per share charge related to the Monticello nuclear facility LCM/EPU project, which in total cost $748 million. In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allowed recovery of the remaining $333 million of costs with no return on this portion of the investment for years 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million in the first quarter of 2015. See Note 5 to the consolidated financial statements for further discussion.

Summary of Ongoing Earnings

Xcel Energy — Xcel Energy's ongoing earnings were flat for the second quarter of 2016 and increased $0.01 per share year-to-date, which excludes the 2015 adjustment for a charge related to the NSP-Minnesota Monticello LCM/EPU project. Higher electric and gas margins in the second quarter of 2016 were primarily due to higher retail electric and natural gas rates across various jurisdictions, non-fuel riders and the impact of favorable weather. These positive factors were offset by higher depreciation, interest charges and property taxes.

PSCo — PSCo's ongoing earnings decreased $0.02 per share for the second quarter of 2016 and $0.01 per share year-to-date. Year-to-date, the positive impact of higher natural gas revenues due to rate increases was more than offset by higher depreciation, O&M expenses, interest charges and the favorable impact of an adjustment to the estimated electric earnings test refund obligation recognized in 2015.

NSP-Minnesota — NSP-Minnesota’s ongoing earnings were flat for the second quarter of 2016 and increased $0.02 per share year-to-date. Year-to-date, higher electric revenues driven by a rate increase in Minnesota (interim, subject to refund) and non-fuel riders were partially offset by higher depreciation, property taxes, O&M expenses and interest charges.

SPS — SPS’ ongoing earnings increased $0.01 for the second quarter of 2016 and $0.03 per share year-to-date. Year-to-date, higher electric margin and lower O&M expenses were partially offset by additional depreciation.

NSP-Wisconsin — NSP-Wisconsin’s ongoing earnings per share were flat for the second quarter of 2016 and decreased $0.01 year-to-date. Year-to-date, higher electric margins primarily driven by an electric rate increase were more than offset by higher O&M expenses and depreciation.

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Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Ongoing earnings decreased by $0.01 for the second quarter of 2016 and $0.02 per share year-to-date. The change was primarily related to higher long-term debt levels.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2016 EPS compared with the same period in 2015:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2015 GAAP diluted EPS	$ 0.39	$ 0.69
Loss on Monticello LCM/EPU project	—	0.16
2015 ongoing diluted EPS	0.39	0.85
Components of change — 2016 vs. 2015		
Higher electric margins [a]	0.07	0.13
Higher natural gas margins [b]	0.01	0.03
Lower O&M expenses	—	0.01
Higher depreciation and amortization	(0.06)	(0.11)
Higher interest charges	(0.02)	(0.04)
Higher taxes (other than income taxes)	(0.01)	(0.02)
Other, net	0.01	0.01
2016 GAAP and ongoing diluted EPS	$ 0.39	$ 0.86

[a] Reflects $0.022 and $0.008 attributable to weather for the three and six months ended June 30, 2016, respectively.
[b] Reflects $0.001 and $(0.008) attributable to weather for the three and six months ended June 30, 2016, respectively.

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 the average customer historically uses per degree of temperature. Accordingly, deviations in weather 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 as defined above to derive the amount of demand associated with the weather impact.

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

	Three Months Ended June 30			Six Months Ended June 30		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
HDD	(3.7)%	(8.1)%	4.9 %	(11.5)%	(2.4)%	(8.6)%
CDD	1.7	(19.1)	25.8	1.7	(19.2)	26.4
THI	15.8	(20.8)	45.5	15.4	(21.0)	45.6

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

	Three Months Ended June 30			Six Months Ended June 30		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
Retail electric	$0.009 [(a)]	$(0.013)	$0.022	$(0.005) [(a)]	$(0.013)	$0.008
Firm natural gas	—	(0.001)	0.001	(0.013)	(0.005)	(0.008)
Total	$0.009	$(0.014)	$0.023	$(0.018)	$(0.018)	$—

(a) Excludes $0.006 and $0.001 favorable weather impact due to electric sales decoupling at NSP-Minnesota for the three and six months ended June 30, 2016, respectively.

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

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	5.6 %	4.8 %	(0.9)%	4.6 %	4.3 %
Electric commercial and industrial	(1.7)	(0.7)	1.0	—	(0.6)
Total retail electric sales	0.5	0.8	0.7	1.0	0.7
Firm natural gas sales	7.5	4.2	N/A	(6.4)	5.8

	Three Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	3.9 %	0.1 %	(5.6)%	0.8 %	0.7 %
Electric commercial and industrial	(2.2)	(1.7)	(0.5)	(0.7)	(1.5)
Total retail electric sales	(0.4)	(1.2)	(1.4)	(0.4)	(0.9)
Firm natural gas sales	5.5	1.6	N/A	(9.7)	3.4

	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	3.3 %	(0.1)%	(3.8)%	(2.2)%	0.5 %
Electric commercial and industrial	(1.1)	(1.0)	0.5	(0.5)	(0.6)

Total retail electric sales	0.3	(0.7)	(0.2)	(1.1)	(0.3)
Firm natural gas sales	3.2	(9.4)	N/A	(12.4)	(2.0)

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	Six Months Ended June 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	2.5 %	(0.3)%	(2.6)%	(1.0)%	0.4 %
Electric commercial and industrial	(1.4)	(1.2)	(0.1)	(0.5)	(1.0)
Total retail electric sales	(0.1)	(1.0)	(0.5)	(0.7)	(0.6)
Firm natural gas sales	1.2	(0.2)	N/A	(3.6)	0.4
	Six Months Ended June 30 (Excluding Leap Day) [(b)]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [(a)]	1.9 %	(0.9)%	(3.2)%	(1.6)%	(0.2)%
Electric commercial and industrial	(2.0)	(1.8)	(0.6)	(1.0)	(1.5)
Total retail electric sales	(0.7)	(1.5)	(1.1)	(1.3)	(1.1)
Firm natural gas sales	0.4	(1.0)	N/A	(4.5)	(0.4)

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

(b) In order to assess comparable periods, Xcel Energy excluded the estimated impact of the 2016 leap day to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 50-60 basis points for retail electric and 80-90 basis points for firm natural gas for the sixth months ended.

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

- PSCo’s residential growth reflects an increased number of customers. The commercial and industrial (C&I) decline was mainly due to lower sales to certain large customers that support the mining industry and oil and gas industries.

- NSP-Minnesota’s residential sales decreased primarily due to lower use per customer, partially offset by an increase in customer additions. The C&I sales declined as a result of lower use by large customers primarily in the manufacturing industry. The sales decrease was partially mitigated by an increase in the number of customers within the small customer class.

- SPS’ residential sales decline was primarily the result of lower use per customer, partially offset by customer additions. The C&I sales decreased as a result of reduced activity within the oil and gas industries for the small customer class. The decline was partially reduced by customer additions in both the large and small customer classes.

- NSP-Wisconsin’s residential sales decrease was primarily attributable to lower use per customer, partially offset by customer additions. The C&I decline was primarily due to reduced sales to small customers in the sand mining industry. The overall decrease was partially offset by an increase in the number of large and small C&I customers as well as greater use per customer in the large C&I class for the oil and gas industries.

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

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

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2016	2015	2016	2015
Electric revenues	$2,224	$2,213	$4,409	$4,438
Electric fuel and purchased power	(856)	(905)	(1,718)	(1,855)
Electric margin	$1,368	$1,308	$2,691	$2,583

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Fuel and purchased power cost recovery	$ (68)	$ (148)
PSCo earnings test refund	(6)	(6)
Trading	4	(4)
Weather decoupling-Minnesota	(5)	(1)
Retail rate increases [(a)]	30	68
Transmission revenue	26	37
Non-fuel riders	3	10
Estimated impact of weather	22	8
Other, net	5	7
Total increase (decrease) in electric revenues	$ 11	$ (29)

(a) Increase is primarily related to the Minnesota Electric Rate Case (interim, subject to and net of estimated provision for refund) and Wisconsin.

Electric Margin

(Millions of Dollars)	Three Months Ended June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Retail rate increases [(a)]	$ 30	$ 68
Transmission revenue, net of costs	11	12
Non-fuel riders	3	10
Estimated impact of weather	22	8
PSCo earnings test refund	(6)	(6)
Weather decoupling-Minnesota	(5)	(1)
Other, net	5	17
Total increase in electric margin	$ 60	$ 108

(a) Increase is primarily due to rate proceedings in Minnesota (interim, subject to and net of estimated provision for refund) and Wisconsin.

Natural Gas Revenues and Margin

Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas has minimal impact on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2016	2015	2016	2015
Natural gas revenues	$259	$284	$825	$1,000
Cost of natural gas sold and transported	(90)	(127)	(402)	(599)
Natural gas margin	$169	$157	$423	$401

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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 June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Purchased natural gas adjustment clause recovery	$ (36)	$ (196)
Estimated impact of weather	1	(6)
Retail rate increases [a]	11	24
Other, net	(1)	3
Total decrease in natural gas revenues	$ (25)	$ (175)

[a] Increase is primarily related to Colorado.

Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30 2016 vs. 2015	Six Months Ended June 30 2016 vs. 2015
Retail rate increases [a]	$ 11	$ 24
Estimated impact of weather	1	(6)
Other, net	—	4
Total increase in natural gas margin	$ 12	$ 22

[a] Increase is primarily related to Colorado.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $2.7 million, or 0.5 percent, for the second quarter of 2016 and decreased $5.7 million, or 0.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. The year-to-date decrease was mainly due to the timing and scope of plant outages and discovery work along with lower nuclear outage and outage amortization costs, which were partially offset by higher gas survey and damage prevention costs.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $1.8 million, or 3.3 percent, for the second quarter of 2016 and $5.4 million, or 5.0 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to higher electric and natural gas recovery rates at NSP-Minnesota, partially reduced by lower electric recovery rates at PSCo. Higher conservation and DSM program expenses are generally offset by higher revenues.

Depreciation and Amortization — Depreciation and amortization increased $47.9 million, or 17.5 percent, for the second quarter of 2016 and $94.9 million, or 17.3 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to capital investments, including Pleasant Valley and Border

Wind Farms, which were placed into service in late 2015.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $8.7 million, or 6.7 percent, for the second quarter of 2016 and $17.4 million, or 6.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. Increases were due to higher property taxes primarily in Minnesota.

Interest Charges — Interest charges increased $18.8 million, or 13.0 percent, for the second quarter of 2016 and $30.3, or 10.5 percent, for the six months ended June 30, 2016 compared with the same periods in 2015. The increase was related to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $5.5 million for the second quarter of 2016 compared with the same period in 2015. The decrease was primarily due to lower pretax earnings in 2016 and increased wind production tax credits in 2016. The ETR was 34.7 percent for the second quarter of 2016 compared with 35.8 percent for the same period in 2015. The lower ETR in 2016 is primarily due to increased wind production tax credits.

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Income tax expense increased $39.6 million for the first six months of 2016 compared with the same period in 2015. The increase in income tax expense was primarily due to higher pretax earnings in the six months ended June 30, 2016, partially offset by increased wind production tax credits. The ETR was 34.7 percent for the first six months of 2016 compared with 35.7 percent for the same period in 2015. The lower ETR in 2016 is primarily due to increased wind production tax credits.

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, 2015 and Public Utility Regulation included in Item 2 of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016, appropriately represent, in all material respects, the current status of public utility regulation, and are incorporated herein by reference.

NSP-Minnesota

NSP System Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Integrated Resource Plan (the Plan) with the MPUC.

Subsequently, NSP-Minnesota proposed revisions to the Plan, which addressed stakeholder recommendations as well as the Clean Power Plan (CPP) issued by the EPA. The revised Plan is based on four primary elements: (1) accelerate the transition from coal energy to renewables, (2) preserve regional system reliability, (3) pursue energy efficiency gains and grid modernization, and (4) ensure customer benefits. The provisions included in the Plan would allow for a 60 percent reduction in carbon emissions from 2005 levels by 2030 and is expected to result in 63 percent of NSP System energy being carbon-free by 2030. NSP-Minnesota believes its Plan provides substantial opportunities for the ownership of renewable generation and replacement cost generation.

Specific terms of the proposal include:

- The addition of 800 MW of wind and 400 MW of utility scale solar to the pre-2020 time-frame;
- The addition of 1000 MW of wind and 1000 MW of utility scale solar between 2020-2030;
- The retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026;
- The addition of a 230 MW natural gas combustion turbine in North Dakota by the end of 2025;
- Replacement of Sherco coal generation with a 786 MW natural gas combined cycle unit at the Sherco site no later than 2026; and
- Operation of the Monticello and PI nuclear plants through their current license periods in the early 2030's.

In January 2016, NSP-Minnesota filed supplemental economic and technical information in support of its revised Plan. Additionally, NSP-Minnesota addressed forecasted cost increases at PI (through end of licensed life) and committed to provide additional information if the MPUC wishes to further explore alternatives to operating PI through its current license periods. In July 2016, the DOC submitted its comments, which:

- Concluded NSP-Minnesota's revised Plan is the most cost-effective after analyzing alternative retirement scenarios for Sherco Units 1 and 2 and a possible retirement of the King plant;
- Recommended a separate detailed analysis of early PI retirement;
- Recommended no additional solar beyond the community solar gardens program for the first five years; and
- Recommended adding up to 1,000 MW of wind by 2019.

The MPUC is expected to make a decision on the Plan in late 2016.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2015 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, 2015 and Nuclear Power Operations included in Item 2 of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

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NSP-Wisconsin

2015 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the year ended Dec. 31, 2015 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 load as a result of mild weather, lower natural gas prices and lower purchased power prices in the MISO market. NSP-Wisconsin recorded a deferral of approximately $9.2 million through Dec. 31, 2015. In July 2016, the PSCW required NSP-Wisconsin to provide a direct refund of $9.5 million to customers. Accordingly, NSP-Wisconsin plans to apply the refund to customer bills based on usage in September 2016.

2016 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for the six months ended June 30, 2016 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. 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 $3.5 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 $3.3 million through June 30, 2016. 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 2017, NSP-Wisconsin will file a reconciliation of 2016 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-2017.

PSCo

Colorado 2017 Electric Resource Plan — In May 2016, PSCo filed its 2017 Electric Resource Plan which identified approximately 600 MW of additional resources need by the summer of 2023. The CPUC is expected to consider the resource plan in two phases. In the first phase, the CPUC will examine the resource need to address peak demand periods, establish the resource acquisition period and determine modeling parameters used in resource selection for the second phase. The second phase would include solicitation of new resources. PSCo's base plan, filed in Phase I, addressed various resources including 410 MW of combined cycle generation, 700 MW of combustion turbine generation and approximately 600 MW of customer sited solar generation. Additional scenarios to the plan include adding 600 MW of the Rush Creek Wind Project or 400 MW of wind or utility solar generation. The first phase of the Electric Resource Plan is anticipated to conclude in the second quarter of 2017 with the second phase to begin shortly after.

Brush to Castle Pines 345 Kilovolt (KV) Transmission Line — In April 2015, the CPUC granted a certificate of public convenience and necessity (CPCN) to construct a new 345 KV transmission line originating from Pawnee generating station, near Brush, CO to the Daniels Park substation, near Castle Pines, CO to be placed in service by May 2022. The estimated project cost is $178.3 million. The CPUC's decision requires that project construction begin no earlier than May 2020 to meet resource needs by 2023.

In April 2016, PSCo filed a petition with the CPUC to request that construction begin as early as February 2017 for the project to be placed in service by October 2019. This project was proposed to support the interconnection of new generation at PSCo's Pawnee or Missile Site substations. As the Rush Creek Wind Project interconnects at the Missile Site substation, parties have requested that PSCo's petition to start construction in 2017 be consolidated with the Rush Creek Wind Project. The CPUC granted the request for consolidation and a decision on the petition is expected by November 2016.

Rush Creek Wind Ownership Proposal — In May 2016, PSCo filed an application to build, own and operate a 600 MW wind generation facility at a cost of approximately $1 billion, including transmission investment. PSCo requested approval of the proposal by November 2016, in order to commence the project timely and capture the full production tax credit benefit for customers.

Colorado legislation allows for utilities to own up to 50 percent of new renewable resources without a competitive bidding process if projects can be developed at a reasonable price and demonstrate economic benefit.

PSCo believes its proposed facility can be constructed at a reasonable cost compared to the cost of similar renewable resources available on the market, and that it will be able to demonstrate to the CPUC and the independent evaluator that the proposed wind project meets the reasonable price and economic benefit standards. If approved by the CPUC, the new facility is projected to go into service in December 2018.

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Intervenors responded to PSCo’s application and answer testimony was filed in July 2016. The next steps in the procedural schedule are as follows:

- PSCo’s rebuttal testimony — Aug. 22, 2016; and
- Hearings — Sept. 7-9, 2016.

Natural Gas Reserves Investments — In January 2016, PSCo filed a request with the CPUC for approval of a long-term natural gas procurement and price hedging framework. In June 2016, PSCo withdrew its application as it concluded that the litigation of the application would be contentious and, as structured, the framework would not address many of the concerns raised about the program by various intervenors. PSCo will continue to examine opportunities to mitigate price volatility for its customers.

Joint Dispatch Agreement (JDA) — In February 2016, the FERC approved a JDA between PSCo, Black Hills Colorado Electric Utility Company, LP and Platte River Power Authority. Through the JDA, energy is dispatched to economically serve the combined electric customer loads of the three systems. In circumstances where PSCo is the lowest cost producer, it will sell its excess generation to other JDA counterparties. Margins on these sales would be shared among PSCo and its customers, of which 10 percent would be retained by PSCo. The JDA parties estimate the combined net benefits of the agreement would be approximately $4.5 million, annually. The agreement results in a reduction in total energy costs for the parties, of which approximately $1.4 million would be allocated to PSCo’s customers. As part of the agreement, PSCo will earn a management fee to administer the JDA. Operations under the JDA are expected to begin in August 2016.

Advanced Grid Intelligence and Security — In August 2016, PSCo filed a request with the CPUC to approve a certificate of public convenience and necessity (CPCN) for implementation of its advanced grid initiative. The project incorporates installing advanced meters, implementing a combination of hardware and software applications to allow the distribution system to operate at a lower voltage (integrated volt-var optimization) and installing necessary communications infrastructure to implement this hardware. These major projects are expected to improve customer experience, enhance grid reliability and enable the implementation of new and innovative programs and rate structures. The estimated capital investment for the project is approximately $500 million, which is largely included in Xcel Energy’s base capital forecast for 2016-2020. The project would be completed by 2021.

Decoupling Filing — On July 12, 2016, PSCo filed a request with the CPUC to approve a partial decoupling mechanism for a five year period, effective in 2017. The proposed decoupling adjustment would allow PSCo to adjust annual revenues based on changes in weather normalized average use per customer for the residential and small C&I classes. The proposed mechanism is intended to improve PSCo’s ability to collect base rate revenues in the event that average use per customer declines as a result of DSM, distributed generation and other energy saving programs. The proposed decoupling mechanism is symmetric and may result in potential refunds to customers if there were an increase in average use per customer. PSCo did not request that revenue be adjusted as a result of weather related sales fluctuations.

SPS

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In June 2015, SPS filed a certificate of convenience and necessity (CCN) with the PUCT for the Yoakum County to Texas/New Mexico State line portion of this 345 KV line project. The PUCT approved this CCN in March 2016. CCNs for the TUCO to Yoakum County substation segment were filed in June 2016. CCNs for the Texas/New Mexico state line to

Hobbs Plant segment are planned to be filed in the second half of 2016. The estimated project cost is $242 million. This line is scheduled to be in service in 2019.

Hobbs Plant Substation to China Draw Substation 345 KV Transmission Line — In May 2016, SPS filed a CCN with the NMPRC for the Hobbs Plant to China Draw transmission line. The estimated project cost is approximately $163 million. The line is anticipated to be in service in 2018.

Wholesale Customer Participation in 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 based on 2015 revenue requirements. 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 revenue requirement would be spread across a smaller base of customers. SPS intends to participate in the PUCT's proceeding to protect its customers' interests. LP&L has stated that it intends to file an application with the PUCT for a CCN for approval of the transfer by late 2016.

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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 has stated it intends to discuss, and possibly decide, issues regarding procedures, timing, scope of proceedings and types of analyses in August 2016.

In May 2016, SPS submitted a filing to the FERC seeking approval to impose an Interconnection Switching Fee (exit fee) associated with LP&L's proposal. In June 2016, LP&L and Golden Spread Electric Cooperative, Inc. (Golden Spread) protested SPS' filing. LP&L argued that SPS has no legal authority to impose a charge and LP&L's departure would reduce certain costs to SPS and asked the FERC to reject the filing. Golden Spread asked FERC to clarify that if the exit fee is not approved, remaining wholesale transmission customers could challenge future recovery of SPS' costs. Additionally, the PUCT asked FERC to hold the filing in abeyance pending the outcome of the PUCT proceedings evaluating the LP&L proposal. SPS requested FERC to act on the matter by mid-September 2016.

Summary of Recent Federal Regulatory Developments

The Pipeline and Hazardous Materials Safety Administration

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act (Pipeline Safety Act) requires additional verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. The DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) recently released proposed rules that address this verification requirement along with a number of other significant changes to gas transmission regulations. These changes include requirements around use of automatic or remote-controlled shut-off valves; testing of certain previously untested transmission lines; and expanding integrity management requirements. The Pipeline Safety Act also includes a maximum penalty for violating pipeline safety rules of $2 million per day for related violations.

Xcel Energy recently commented on the proposed rules and continues to analyze the proposed rule changes as they relate to costs, current operations and financial results. PHMSA has indicated that they intend for the rules to go into effect in late 2016.

Xcel Energy has been taking actions that were intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo and NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA and GUIC riders, respectively.

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, 2015 and Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — The FERC has adopted a new two-step ROE methodology for electric utilities. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. Two complaints against the MISO TOs, including NSP-Minnesota and NSP-Wisconsin, are pending FERC action after issuance of initial decisions by ALJs in December 2015 and June 2016, respectively. FERC is not expected to issue orders in any of the litigated ROE complaint proceedings until later in 2016 or 2017. See Note 5 to the consolidated financial statements for discussion of the MISO ROE Complaints.

SPS Asset Transfer to Xcel Energy Southwest Transmission Company, LLC (XEST) — In 2015 through early 2016, SPS submitted filings to the FERC, PUCT, NMPRC and Kansas Corporation Commission (KCC) seeking approval to transfer ownership of SPS' 345 KV transmission assets in Kansas and Oklahoma to XEST at net book value of approximately $103 million.

In June 2016, SPS and XEST made filings to withdraw the pending PUCT, NMPRC, KCC and FERC applications due to the relatively slow pace of Order 1000 competitive transmission development projects in the SPP. All withdrawal requests have been granted, and the matters are now closed.

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Formula Rate Treatment of Accumulated Deferred Income Taxes (ADIT) — In 2015, the MISO TOs, including NSP-Minnesota and NSP-Wisconsin, SPS and PSCo filed separate changes to their transmission formula rates and the PSCo production formula rate to modify the treatment of ADIT to comply with IRS guidance regarding how ADIT must be reflected in formula rates using future test years and a true-up. The filings were intended to ensure that NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are in compliance with IRS rules and may continue to use accelerated tax depreciation.

Golden Spread protested the proposed changes to the SPS transmission formula rate. In December 2015, the FERC partially accepted the proposed NSP-Minnesota and NSP-Wisconsin transmission formula rate changes, but rejected the changes regarding the treatment of ADIT in the formula rate true-up. NSP-Minnesota and NSP-Wisconsin sought clarification or rehearing of the FERC order partially rejecting the NSP System filing. In April 2016, FERC accepted the SPS and PSCo formula rate changes, subject to a compliance filing. SPS and PSCo submitted the compliance filings in May 2016. FERC action on the NSP-Minnesota and NSP-Wisconsin request for clarification remains pending.

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.

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 and energy-related instruments. 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 June 30, 2016, the fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 2,378	$ 6,871	$ 1,204	$ 101	$ 10,554
PSCo	1	332	47	—	—	379
		$ 2,710	$ 6,918	$ 1,204	$ 101	$ 10,933

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	Options					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	2	$ (839)	$ —	$ —	$ —	$ (839)

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:

	Six Months Ended June 30	
(Thousands of Dollars)	2016	2015
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 11,040	$ 21,811
Contracts realized or settled during the period	(1,406)	3,472
Commodity trading contract additions and changes during period	460	(6,035)
Fair value of commodity trading net contract assets outstanding at June 30	$ 10,094	$ 19,248

At June 30, 2016, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.1 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.1 million. At June 30, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.4 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, including transactions that are not recorded at fair value, 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 June 30	VaR Limit	Average	High	Low
2016	$ 0.22	$ 3.00	$ 0.22	$ 0.38	$ 0.06
2015	0.47	3.00	0.23	1.30	0.06

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 87 percent of its 2016 and approximately 13 percent of its 2017 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 36 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.

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 June 30, 2016 and 2015, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $5.9 million and $4.5 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

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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 June 30, 2016, 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 do not have an 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 June 30, 2016, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $9.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $16.4 million. At June 30, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $3.4 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $4.5 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.

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 June 30, 2016. 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 June 30, 2016.

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 1.5 percent and 8.5 percent of total assets and liabilities, respectively, measured at fair value at June 30, 2016.

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 observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $28.1 million and $3.6 million of estimated fair values, respectively, for FTRs held at June 30, 2016.

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 immaterial Level 3 commodity forwards and options held at June 30, 2016.

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Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	Six Months Ended June 30 2016	2015
Cash provided by operating activities	$1,413	$1,509

Net cash provided by operating activities decreased $96 million for the six months ended June 30, 2016 compared with the six months ended June 30, 2015. The decrease was primarily due to timing of customer receipts, refunds and recovery on certain electric and natural gas riders and incentive programs, partially offset by timing of vendor payments and higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation, deferred tax expenses and a charge related to the Monticello LCM/EPU project in 2015).

(Millions of Dollars)	Six Months Ended June 30 2016	2015
Cash used in investing activities	$(1,443)	$(1,431)

Net cash used in investing activities increased $12 million for the six months ended June 30, 2016 compared with the six months ended June 30, 2015. The increase was primarily attributable to the establishment of rabbi trusts in 2016 and the impact of higher insurance proceeds received in 2015, partially offset by higher payments for capital expenditures in 2015 related to the completion of certain generation and transmission projects.

(Millions of Dollars)	Six Months Ended June 30 2016	2015
Cash provided by (used in) financing activities	$23	$(22)

Net cash provided by financing activities was $23 million for the six months ended June 30, 2016 compared with net cash used in financing activities of $22 million for the six months ended June 30, 2015, or a change of $45 million. The difference was primarily due to higher debt issuances and lower repayments of short-term debt, partially offset by repayments of long-term debt and higher dividend payments in 2016.

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.

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 2017. 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 2016, contributions of $125.0 million were made across four of Xcel Energy's pension plans;
- In 2015, contributions of $90.0 million were made across four of Xcel Energy's pension plans; and
- For future years, we anticipate contributions will be made as necessary.

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 June 30, 2016, approximately $9.1 million of cash was held in these accounts.

Amended Credit Agreements - In June 2016, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements remained at $2.75 billion. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the following exceptions:

- The maturity extended from October 2019 to June 2021.
- The Eurodollar borrowing margins on these lines of credit were reduced to a range of 75 to 150 basis points per year, from a range of 87.5 to 175 basis points per year, based upon applicable long-term credit ratings.
- The commitment fees, calculated on the unused portion of the lines of credit, were reduced to a range of 6 to 22.5 basis points per year, from a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc., NSP-Minnesota, PSCo, and SPS 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.

Credit Facilities — As of July 25, 2016, 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	$ 401	$ 599	$ —	$ 599
PSCo	700	98	602	1	603
NSP-Minnesota	500	18	482	1	483
SPS	400	95	305	1	306
NSP-Wisconsin	150	23	127	—	127
Total	$ 2,750	$ 635	$ 2,115	$ 3	$ 2,118

[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.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2016		Year Ended Dec. 31, 2015	
Borrowing limit	$2,750		$2,750	
Amount outstanding at period end	447		846	
Average amount outstanding	404		601	
Maximum amount outstanding	841		1,360	
Weighted average interest rate, computed on a daily basis	0.72	%	0.48	%
Weighted average interest rate at period end	0.80		0.82	

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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.

Xcel Energy Inc.'s and its utility subsidiaries' 2016 financing plans reflect the following:

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046;
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046; and
- SPS plans to issue approximately $300 million of first mortgage bonds in the third quarter.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

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

Xcel Energy's 2016 ongoing earnings guidance is $2.12 to $2.27 per share. Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to decrease by approximately 0.5 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 1 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $200 million over 2015 levels. Approximately $20 million of the increased depreciation expense and amortization will be recovered through the renewable development fund rider (not included in the capital rider) in Minnesota.
- Property taxes are projected to increase approximately $40 million to $50 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2015 levels.
- AFUDC — equity is projected to increase approximately $0 million to $10 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

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 4 percent to 6 percent, based on ongoing 2015 EPS of $2.10, which was the mid-point of Xcel Energy's 2015 ongoing guidance range;
- 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 June 30, 2016, 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

Effective January 2016, Xcel Energy implemented the general ledger modules of a new enterprise resource planning (ERP) system to improve certain financial and related transaction processes. During 2016 and 2017, Xcel Energy will continue implementing additional modules and expects to begin conversion of existing work management systems to this new ERP system. In connection with this ongoing implementation, Xcel Energy has updated and will continue updating its internal control over financial reporting, as necessary, to accommodate modifications to its business processes and accounting procedures. Xcel Energy does not expect the implementation of the additional modules to materially affect 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 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, 2015, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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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 June 30, 2016:

	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
April 1, 2016 — April 30, 2016	—	$ —	—	—
May 1, 2016 — May 31, 2016	—	—	—	—
June 1, 2016 — June 30, 2016	—	—	—	—
Total	—		—	—

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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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 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Xcel Energy Inc. Bylaws, as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 17, 2016 (file no. 001-03034)).
4.01*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $350,000,000 principal amount of 3.600 percent First Mortgage Bonds, Series due May 15, 2046. (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated May 31, 2016 (file no. 001-31387)).
4.02*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250,000,000 principal amount of 3.55 percent First Mortgage Bonds, Series No. 29 due 2046. (Exhibit 4.01 to Form 8-K of PSCo dated June 13, 2016 (file no. 001-03280)).
10.01+	Fifth Amendment dated May 3, 2016 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy.
10.02*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.01 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
10.03*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.02 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
10.04*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.03 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
10.05*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.04 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
10.06*	Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.05 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).
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 June 30, 2016 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.

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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.

Aug. 4, 2016 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)