XCEL ENERGY INC
Form 10-Q
May 10, 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 March 31, 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 May 4, 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 March 31	
	2016	2015
Operating revenues		
Electric	$2,185,119	$2,224,863
Natural gas	565,689	715,996
Other	21,465	21,360
Total operating revenues	2,772,273	2,962,219
Operating expenses		
Electric fuel and purchased power	861,852	950,132
Cost of natural gas sold and transported	312,117	472,371
Cost of sales — other	8,245	10,049
Operating and maintenance expenses	577,410	585,830
Conservation and demand side management program expenses	57,436	53,805
Depreciation and amortization	320,020	273,098
Taxes (other than income taxes)	145,323	136,626
Loss on Monticello life cycle management/extended power uprate project	—	129,463
Total operating expenses	2,282,403	2,611,374
Operating income	489,870	350,845
Other income, net	4,250	3,161
Equity earnings of unconsolidated subsidiaries	13,182	7,776
Allowance for funds used during construction — equity	13,113	12,660
Interest charges and financing costs		
Interest charges — includes other financing costs of $6,336 and $5,698, respectively	156,443	144,940
Allowance for funds used during construction — debt	(5,990)	(6,144)
Total interest charges and financing costs	150,453	138,796
Income before income taxes	369,962	235,646
Income taxes	128,650	83,580
Net income	$241,312	$152,066
Weighted average common shares outstanding:		
Basic	508,667	506,983
Diluted	509,150	507,393

Earnings per average common share:		
Basic	$0.47	$0.30
Diluted	0.47	0.30
Cash dividends declared per common share	$0.34	$0.32

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 March 31	
	2016	2015
Net income	$ 241,312	$ 152,066
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $142 and $569, respectively	211	876
Derivative instruments:		
Net fair value decrease, net of tax of $(2) and $(7), respectively	(4)	(11)
Reclassification of losses to net income, net of tax of $604 and $382, respectively	938	585
	934	574
Marketable securities:		
Net fair value increase, net of tax of $0 and $0, respectively	—	1
Other comprehensive income	1,145	1,451
Comprehensive income	$ 242,457	$ 153,517

See Notes to Consolidated Financial Statements

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

	Three Months Ended March 31	
	2016	2015
Operating activities		
Net income	$241,312	$152,066
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	323,761	277,388
Conservation and demand side management program amortization	1,162	1,451
Nuclear fuel amortization	25,750	28,465
Deferred income taxes	160,379	82,773
Amortization of investment tax credits	(1,307)	(1,384)
Allowance for equity funds used during construction	(13,113)	(12,660)
Equity earnings of unconsolidated subsidiaries	(13,182)	(7,776)
Dividends from unconsolidated subsidiaries	11,481	9,876
Share-based compensation expense	13,099	10,225
Loss on Monticello life cycle management/extended power uprate project	—	129,463
Net realized and unrealized hedging and derivative transactions	5,576	12,778
Other	(388)	—
Changes in operating assets and liabilities:		
Accounts receivable	(4,780)	(291)
Accrued unbilled revenues	129,444	183,974
Inventories	88,570	92,010
Other current assets	(16,635)	56,685
Accounts payable	(22,063)	(99,029)
Net regulatory assets and liabilities	34,404	146,097
Other current liabilities	(44,929)	34,642
Pension and other employee benefit obligations	(118,774)	(85,469)
Change in other noncurrent assets	(1,196)	(5)
Change in other noncurrent liabilities	(8,508)	(25,885)
Net cash provided by operating activities	790,063	985,394
Investing activities		
Utility capital/construction expenditures	(700,319)	(770,609)
Proceeds from insurance recoveries	—	24,241
Allowance for equity funds used during construction	13,113	12,660
Purchases of investments in external decommissioning fund	(109,373)	(387,826)
Proceeds from the sale of investments in external decommissioning fund	104,280	386,111
Investments in WYCO Development LLC and other	(260)	(321)
Other, net	(1,548)	(2,645)
Net cash used in investing activities	(694,107)	(738,389)
Financing activities		
Repayments of short-term borrowings, net	(663,000)	(50,500)
Proceeds from issuance of long-term debt	747,127	—
Repayments of long-term debt	(333)	(455)

Proceeds from issuance of common stock	—	1,411
Purchase of common stock for settlement of equity awards	(789)	—
Dividends paid	(162,410)	(144,025)
Net cash used in financing activities	(79,405)	(193,569)
Net change in cash and cash equivalents	16,551	53,436
Cash and cash equivalents at beginning of period	84,940	79,608
Cash and cash equivalents at end of period	$101,491	$133,044
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(164,511)	$(161,717)
Cash received for income taxes, net	7,414	62,697
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$192,818	$239,905
Issuance of common stock for reinvested dividends and 401(k) plans	7,703	14,433

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)

	March 31, 2016	Dec. 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$101,491	$84,940
Accounts receivable, net	729,386	724,606
Accrued unbilled revenues	525,423	654,867
Inventories	520,054	608,584
Regulatory assets	317,489	344,630
Derivative instruments	23,293	33,842
Deferred income taxes	180,513	140,219
Prepaid taxes	180,825	163,023
Prepayments and other	154,143	155,734
Total current assets	2,732,617	2,910,445
Property, plant and equipment, net	31,433,406	31,205,851
Other assets		
Nuclear decommissioning fund and other investments	1,917,709	1,902,995
Regulatory assets	2,897,502	2,858,741
Derivative instruments	55,612	51,083
Other	32,998	32,581
Total other assets	4,903,821	4,845,400
Total assets	$39,069,844	$38,961,696
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$656,516	$657,021
Short-term debt	183,000	846,000
Accounts payable	809,656	960,982
Regulatory liabilities	272,647	306,830
Taxes accrued	525,934	438,189
Accrued interest	148,112	166,829
Dividends payable	172,704	162,410
Derivative instruments	27,553	29,839
Other	392,446	490,197
Total current liabilities	3,188,568	4,058,297
Deferred credits and other liabilities		
Deferred income taxes	6,493,644	6,293,661
Deferred investment tax credits	67,112	68,419
Regulatory liabilities	1,373,140	1,332,889
Asset retirement obligations	2,639,628	2,608,562
Derivative instruments	167,299	168,311

Customer advances	221,683	228,999
Pension and employee benefit obligations	812,998	941,002
Other	285,743	261,756
Total deferred credits and other liabilities	12,061,247	11,903,599
Commitments and contingencies		
Capitalization		
Long-term debt	13,148,395	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 March 31, 2016 and Dec. 31, 2015, respectively	1,269,882	1,268,839
Additional paid in capital	5,889,939	5,889,106
Retained earnings	3,620,421	3,552,728
Accumulated other comprehensive loss	(108,608)	(109,753)
Total common stockholders' equity	10,671,634	10,600,920
Total liabilities and equity	$39,069,844	$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 March 31, 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				152,066		152,066
Other comprehensive income					1,451	1,451
Dividends declared on common stock				(163,120)		(163,120)
Issuances of common stock	931	2,326	893			3,219
Share-based compensation			6,772			6,772
Balance at March 31, 2015	506,664	$1,266,659	$5,844,995	$3,209,904	$ (106,688)	$10,214,870
Balance at Dec. 31, 2015	507,536	$1,268,839	$5,889,106	$3,552,728	$ (109,753)	$10,600,920
Net income				241,312		241,312
Other comprehensive income					1,145	1,145
Dividends declared on common stock				(173,619)		(173,619)
Issuances of common stock	417	1,043	(3,755)			(2,712)
Purchase of common stock for settlement of equity awards			(789)			(789)
Share-based compensation			5,377			5,377
Balance at March 31, 2016	507,953	$1,269,882	$5,889,939	$3,620,421	$ (108,608)	$10,671,634

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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 March 31, 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 months ended March 31, 2016 and 2015; and its cash flows for the three months ended March 31, 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 March 31, 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.

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.

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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 is currently evaluating the impact of adopting ASU 2016-09 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 are 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)	March 31, 2016	Dec. 31, 2015
Accounts receivable, net		
Accounts receivable	$778,953	$776,494
Less allowance for bad debts	(49,567)	(51,888)
	$729,386	$724,606

(Thousands of Dollars)	March 31, 2016	Dec. 31, 2015
Inventories		
Materials and supplies	$298,345	$290,690
Fuel	172,098	202,271
Natural gas	49,611	115,623
	$520,054	$608,584

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(Thousands of Dollars)	March 31, 2016	Dec. 31, 2015
Property, plant and equipment, net		
Electric plant	$36,604,585	$36,464,050
Natural gas plant	5,017,324	4,944,757
Common and other property	1,720,351	1,709,508
Plant to be retired [(a)]	34,606	38,249
Construction work in progress	1,486,070	1,256,949
Total property, plant and equipment	44,862,936	44,413,513
Less accumulated depreciation	(13,790,489)	(13,591,259)
Nuclear fuel	2,450,363	2,447,251
Less accumulated amortization	(2,089,404)	(2,063,654)
	$31,433,406	$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 and $12 million in 2013 and $15 million in 2012.

Federal Audit — Xcel Energy files a consolidated federal income tax return. In the third quarter of 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of March 31, 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); 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 March 31, 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 March 31, 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, the state of Texas began an audit of years 2009 and 2010. As of March 31, 2016, the state of Texas had not proposed any adjustments, and 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)	March 31, 2016	Dec. 31, 2015
Unrecognized tax benefit — Permanent tax positions	$ 26.3	$ 25.8
Unrecognized tax benefit — Temporary tax positions	96.2	94.9
Total unrecognized tax benefit	$ 122.5	$ 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)	March 31, 2016	Dec. 31, 2015
NOL and tax credit carryforwards	$ (38.5)	$ (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 Texas audit progresses and other state audits resume. As the IRS Appeals, IRS audit, and Texas audit 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 March 31, 2016 and Dec. 31, 2015 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 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, 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)

NSP-Minnesota – 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

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years. In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016.

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The major components of the requested rate increase are summarized below:

(Millions of Dollars)	2016	2017	2018	Total
2014 multi-year rate case items:				
Excess depreciation reserve	$26.0	$51.0	$—	$77.0
Department of Energy (DOE) settlement	25.7	—	—	25.7
Monticello life cycle management (LCM)/extended power uprate (EPU)	11.2	(1.6)	(1.5)	8.1
	62.9	49.4	(1.5)	110.8
Additional items:				
Capital investments	128.7	12.8	44.6	186.1
Property taxes	30.2	7.6	5.2	43.0
NOL carryforwards	(6.3)	(24.5)	(6.5)	(37.3)
Other costs	(20.9)	6.8	8.6	(5.5)
	131.7	2.7	51.9	186.3
Total rate request	$194.6	$52.1	$50.4	$297.1

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

- Intervenors' direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- Administrative Law Judge (ALJ) report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

NSP-Minnesota – 2016 Transmission Cost Recovery (TCR) Filing — In October 2015, NSP-Minnesota submitted its 2016 TCR filing with the MPUC, requesting recovery of $19.2 million of 2016 transmission investment costs not included in electric base rates. This filing included an option to keep approximately $59.1 million of revenue requirements associated with two CapX2020 projects completed in 2015 within the TCR rider or to include these revenue requirements in electric base rates during the interim rate implementation of the next electric rate case. In November 2015, NSP-Minnesota submitted an update to its TCR filing in which it confirmed that it was requesting the MPUC approve keeping the two CapX2020 projects in the TCR rider, increasing the revenue requirements to $78.3 million, until the conclusion of the 2016 Minnesota electric rate case.

In April 2016, NSP-Minnesota received comments from the Minnesota Department of Commerce (DOC) requesting additional support for the costs incurred for the CapX2020 La Crosse-Madison project and the CapX2020 Big Stone-Brookings project, as well as the updated financial impact for the actual non-prorated accumulated deferred income tax (ADIT) as opposed to the forecasted prorated ADIT used in the cost recovery calculations. An MPUC decision is expected later in 2016.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/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.

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NSP-Wisconsin

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

Wisconsin 2017 Electric and Gas Rate Case — On April 1, 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.

The electric rate request is for the limited purpose of recovering increases in (i) generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with NSP-Minnesota, and (ii) 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 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.

The major components of the requested rate increases are summarized below:

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

(a) Includes Interchange Agreement billings. The Interchange Agreement is a Federal Energy Regulatory Commission (FERC) tariff under which NSP-Wisconsin and its affiliate, NSP-Minnesota, own and operate a single integrated electric generation and transmission system and both companies pay a pro-rata share of system capital and operating costs. For financial reporting purposes, these expenses are included in operating and maintenance expenses.

Natural Gas Rate Request (Millions of Dollars)	Request
Environmental remediation expenses	$ 4.8
Total natural gas rate increase	$ 4.8

A PSCW decision is anticipated in the fourth quarter of 2016.

PSCo

Pending Regulatory Proceedings — CPUC

PSCo – 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, subject to review by the CPUC. The proposed refund obligation related to the 2015 earnings test was accrued for as of March 31, 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 March 31, 2016.

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SPS

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

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on a historic test year (HTY) ending June 2014, adjusted for known and measurable changes, a ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent.

SPS requested a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014. In June 2015, SPS revised its requested rate increase to $42.1 million.

In December 2015, the PUCT made the following decisions:

- Disallowed SPS' proposed adjustment to jurisdictional allocation factors to reflect Golden Spread Electric Cooperative, Inc.'s wholesale load reductions from 500 MW to 300 MW, effective June 1, 2015;
- Disallowed incentive compensation;
- Approved an equity ratio of 51.00 percent instead of the actual 53.97 percent; and
- A ROE of 9.70 percent.

The following table reflects the ALJs' position and PUCT's decision:

(Millions of Dollars)	ALJs' Proposal for Decision	PUCT Decision
SPS' revised rate request	$ 42.1	$ 42.1
Investment for capital expenditures — post-test year adjustments	(8.9)	(8.9)
Lower ROE	(6.3)	(6.3)
Lower capital structure	—	(3.7)
Annual incentive compensation	(0.2)	(0.3)
O&M expense adjustments	(4.6)	(4.6)
Depreciation expense	(2.7)	(2.7)
Property taxes	(0.9)	(0.9)
Revenue adjustments	(1.1)	(1.6)
Wholesale load reductions	—	(11.5)
Southwest Power Pool, Inc. (SPP) transmission expansion plan	(4.2)	(4.2)
Other, net	1.4	(1.2)
Total, gross of rate case expenses	$ 14.6	$ (3.8)
Adjustment to move rate case expenses to a separate docket	(0.2)	(0.2)
Total, net of rate case expenses	$ 14.4	$ (4.0)
New depreciation rates	(11.2)	(11.2)
Earnings impact	$ 3.2	$ (15.2)

In January 2016, SPS filed its motion for rehearing on capital structure, incentive compensation and known and measurable adjustments, including wholesale load reductions and post test-year capital additions. In February 2016, the PUCT orally denied requests for rehearing. A second motion for rehearing was filed by SPS in March 2016. The PUCT took no action on the motions for rehearing and, as a result, the motions were overruled by operation of law. In

April 2016, SPS filed an appeal of the PUCT's order on rehearing.

SPS – 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 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 request to $68.6 million. The modification reflects actual results for the period of Oct. 1, 2015 through Dec. 31, 2015.

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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.

The final rates established at the end of the case will be made effective relating back to July 20, 2016. A PUCT decision is expected in the first quarter of 2017.

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

SPS – 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 decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power cost adjustment clause (FPPCAC). 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 jurisdictional rate base of approximately $734 million and an equity ratio of 53.97 percent.

On May 2, 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 FPPCAC. The stipulation places no restriction on when SPS may file its next base rate case.

The stipulation is subject to approval by the NMPRC. A decision by the NMPRC on the settlement and implementation of final rates is expected by August 2016.

Pending and Recently Concluded 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 June 2014 the FERC adopted a new ROE methodology, which requires electric utilities to use a two-step discounted cash flow analysis that incorporates both short-term and long-term growth projections to estimate the cost of equity.

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 no earlier than late 2016 or 2017.

Certain MISO TOs separately requested FERC approval of a 50 basis point ROE adder for RTO membership, which was approved effective Jan. 6, 2015, subject to the outcome of the ROE complaint. Certain intervenors sought rehearing of this order, which the FERC denied in 2015.

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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. An ALJ initial decision is expected in June 2016 with a FERC decision expected no earlier than late 2016 or 2017.

NSP-Minnesota has recorded a current liability representing the current best estimate of a refund obligation associated with the new ROE, including the RTO membership adder, as of March 31, 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.

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 sponsored 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.

On April 1, 2016, SPP filed a request with the FERC to recover the charges not billed since 2008. The SPP has indicated the investment subject to the retroactive charges could total \$720 million, but the SPP filing does not quantify the charges that might be billed to individual SPP transmission customers, including SPS. SPS could also collect revenues as it has constructed a sponsored upgrade. On April 22, 2016, SPS protested the SPP filing, arguing that SPP has failed to establish that it is justified. Due to the limited information available and lack of historical precedent, the potential loss to SPS, if any, is not currently estimable. No accrual has been recorded for this matter.

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, 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 3,698 MW of capacity under long-term PPAs as of March 31, 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.

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 March 31, 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.

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

(Millions of Dollars)	March 31, 2016	Dec. 31, 2015
Guarantees issued and outstanding	$ 9.0	$ 12.5
Current exposure under these guarantees	0.1	0.1
Bonds with indemnity protection	42.3	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 Manufactured Gas Plant (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 $68.1 million, of which approximately $50.5 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.

Three other PRPs have contributed $15.9 million to the remediation of the site, as a result of litigation and settlements approved by the U.S. District Court for the Western District of Wisconsin in 2015. NSP-Wisconsin's litigation effort against other PRPs is now complete.

At March 31, 2016 and Dec. 31, 2015, NSP-Wisconsin had recorded a liability of $94.2 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 $17.2 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.

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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 December 2015, the PSCW approved NSP-Wisconsin's 2016 rate case request for an increase to the annual recovery for MGP clean-up costs from $4.7 million to $7.6 million. 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 July 2016 to allow NSP-Minnesota time to further investigate site conditions.

As of March 31, 2016 and Dec. 31, 2015, NSP-Minnesota had recorded a liability of $2.2 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

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 certain national parks and wilderness areas. In their first regional haze state implementation plans (SIPs), Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and particulate matter (PM) emissions under BART and set emissions limits for those facilities.

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the Clean Air Clean Jobs Act (CACJA) emission reduction plan as satisfying regional haze requirements for facilities included within the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at Hayden Unit 1 were placed into service in November 2015 and Hayden Unit 2 is expected to be placed into service in late 2016, at an estimated combined cost of $75.2 million, completing the pollution control equipment required on PSCo plants under the CACJA. PSCo anticipates these costs will be fully recoverable through regulatory mechanisms.

NSP-Minnesota

In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA supplemented its Minnesota SIP in 2012, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, the EPA approved the Minnesota SIP for EGUs and also approved the source-specific emission limits for Sherco Units 1 and 2. The combustion controls were installed first and the scrubber upgrades were completed in December 2014, at a cost of $46.9 million. NSP-Minnesota has included these costs for recovery in rate proceedings.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA’s approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). In January 2016, the Eighth Circuit issued their opinion which upheld the EPA’s approval of the Minnesota SIP. In March 2016, after granting a rehearing request, the Eighth Circuit issued a revised opinion that included additional explanation and continued to uphold the EPA’s approval of the Minnesota SIP.

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SPS

Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for 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 Texas SIP, with the exception that the EPA would substitute 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 in relation to the 2012 particle national ambient air quality standard (NAAQS). In March 2016, the EPA requested information under the Clean Air Act (CAA) related to EGUs at SPS' plants. SPS replied to the request in April 2016 and 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. Xcel Energy cannot evaluate the impact of additional emission controls until the EPA concludes their evaluation of BART. The EPA is expected to issue a proposed rule in December 2016.

In December 2014, the EPA proposed to disapprove the reasonable progress portions of the Texas 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 has asked the court to stay the final rule while it is being reviewed by the court. 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.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the United States Department of the Interior certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota (Minnesota District Court) by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club.

In May 2015, NSP-Minnesota, the EPA and the six environmental advocacy organizations filed a settlement agreement in the Minnesota District Court. The agreement anticipates a federal rulemaking that would impose stricter SO_2 emission limits on Sherco Units 1, 2 and 3, without making a RAVI attribution finding or a RAVI BART determination. The emission limits for Units 1 and 2 reflect the success of a recently completed control project. The Unit 3 emission limits will be met through changes in the operation of the existing scrubber. The Minnesota District Court issued an order staying the litigation for the time needed to complete the actions required by the settlement agreement. The plaintiffs agreed to withdraw their complaint with prejudice when those actions are completed. Plaintiffs also agreed not to request a RAVI certification for Sherco Units 1, 2 and/or 3 in the future.

In March 2016, the EPA adopted a final rule which set the agreed-upon SO_2 emission limits. As a result, the Minnesota District Court dismissed the litigation with prejudice in March 2016. NSP-Minnesota does not anticipate the costs of compliance with the final rule will have a material impact on the results of operations, financial position or cash flows.

Implementation of the NAAQS for SO_2 — The EPA adopted a more stringent NAAQS for SO_2 in 2010. In 2013, the EPA designated areas as not attaining the revised NAAQS, which did not include any areas where Xcel Energy operates power plants. However, many other areas of the country were unable to be classified by the EPA due to a lack of air monitors.

Following a lawsuit alleging that the EPA had not completed its area designations in the time required by the CAA and under a consent decree 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 February 2016, the EPA notified the Texas Commission on Environmental Quality (TCEQ) and the Colorado Department of Health and Environment of its preliminary SO_2 designations. The EPA has proposed to designate the area near the Tolk plant as meeting the standard and the areas near the Harrington and Pawnee plants as "unclassifiable." If finalized as proposed, the unclassifiable areas will be monitored for three years and final designations will be made by December 2020. The EPA's final decision is expected by July 2016.

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If an area is designated nonattainment, 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 in 18 months, designed to achieve the NAAQS within five years. The TCEQ could require additional SO_2 controls on one or more of the units at Tolk and Harrington. 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.

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 June 2015, the City requested the FERC grant rehearing of its order, which the FERC denied in December. The City subsequently appealed this decision to the Ninth Circuit on Feb. 22, 2016.

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.

Preliminary calculations of the City's claim for refunds from PSCo are approximately \$28 million, excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; 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. In making this assessment, PSCo considered two factors. First, notwithstanding PSCo's view that the City has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the scope of the proceeding established by FERC is being challenged in the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City were to establish that it was overcharged for transactions. 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. The cases were consolidated in U.S. District Court in Nevada. In 2009, five of the cases were settled and one was dismissed. The U.S. District Court, in 2011, issued an order dismissing entirely six of the remaining seven lawsuits, and partially dismissing the seventh. Plaintiffs appealed the dismissals to the Ninth Circuit, which reversed the U.S. District Court. The matter was ultimately heard by the U.S. Supreme Court in early 2015, which agreed with the Ninth Circuit and remanded the matter to the U.S. District Court. In September 2015, the District Court held a status conference and set deadlines for certain litigation related activities in 2016. 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 with respect to this matter.

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. On May 9, 2016, the district court granted PSCo’s motion to dismiss the lawsuit, essentially concluding that jurisdiction over this dispute resides with the CPUC. It is uncertain whether plaintiffs will appeal this decision. 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 as the line extension payments from developers, for which DRC is seeking a refund, have served to reduce rate base over the period in dispute. The amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	183	846
Average amount outstanding	774	601
Maximum amount outstanding	1,183	1,360

Weighted average interest rate, computed on a daily basis	0.73 %	0.48 %
Weighted average interest rate at period end	0.63	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 March 31, 2016 and Dec. 31, 2015, there were $29 million of letters of credit outstanding under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

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

At March 31, 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	$ 25	$ 975
PSCo	700	4	696
NSP-Minnesota	500	91	409
SPS	400	87	313
NSP-Wisconsin	150	5	145
Total	$ 2,750	$ 212	$ 2,538

[a] These credit facilities expire in October 2019.
[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 March 31, 2016 and Dec. 31, 2015.

Long-Term Borrowings

In March 2016, 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.

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 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 net asset value 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.

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 include transmission congestion instruments, generally referred to as financial transmission rights (FTRs), purchased from MISO, PJM Interconnection, LLC, Electric Reliability Council of Texas, SPP and New York Independent System Operator. Electric commodity derivatives held by SPS include FTRs purchased from SPP. 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 overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes 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 – including expected plant operating schedules and retail and wholesale demand, 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

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

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota’s regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $322.7 million and $328.8 million at March 31, 2016 and Dec. 31, 2015, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $100.3 million and $100.2 million at March 31, 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 March 31, 2016 and Dec. 31, 2015:

	March 31, 2016					
		Fair Value				
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [(b)]	Total
Nuclear decommissioning fund [(a)]						
Cash equivalents	$11,899	$11,899	$—	$ —	$ —	$11,899
Commingled funds	390,345	—	—	—	395,709	395,709
International equity funds	264,340	—	—	—	242,312	242,312
Private equity investments	108,882	—	—	—	158,915	158,915
Real estate	73,577	—	—	—	100,576	100,576
Debt securities:						
Government securities	24,320	—	23,213	—	—	23,213
U.S. corporate bonds	76,952	—	70,723	—	—	70,723
International corporate bonds	18,117	—	17,343	—	—	17,343
Municipal bonds	47,088	—	49,902	—	—	49,902
Asset-backed securities	2,841	—	2,836	—	—	2,836
Mortgage-backed securities	11,065	—	11,407	—	—	11,407
Equity securities:						
Common stock	481,968	649,015	—	—	—	649,015
Total	$1,511,394	$660,914	$175,424	$ —	$ 897,512	$1,733,850

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $132.8 million of equity investments in unconsolidated subsidiaries and $51.1 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.

	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 three months ended March 31, 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 March 31, 2016:

(Thousands of Dollars)	Final Contractual Maturity Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$3,144	$20,069	$23,213
U.S. corporate bonds	—	18,909	56,102	(4,288)	70,723
International corporate bonds	—	2,795	11,505	3,043	17,343
Municipal bonds	151	266	16,323	33,162	49,902
Asset-backed securities	—	—	2,836	—	2,836
Mortgage-backed securities	—	—	—	11,407	11,407
Debt securities	$151	$21,970	$89,910	$63,393	$175,424

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 March 31, 2016, accumulated other comprehensive losses related to interest rate derivatives included $3.5 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, which is made up of management personnel not directly involved in the activities governed by this policy.

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

At March 31, 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 months ended March 31, 2016 and 2015.

At March 31, 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.

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The following table details the gross notional amounts of commodity forwards, options and FTRs at March 31, 2016 and Dec. 31, 2015:

(Amounts in Thousands) [a][b]	March 31, 2016	Dec. 31, 2015
Megawatt hours of electricity	29,130	50,487
Million British thermal units of natural gas	37,663	20,874
Gallons of vehicle fuel	106	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 months ended March 31, 2016 and 2015, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2016				
	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$1,485 [a]	$—	$—
Vehicle fuel and other commodity	(6)	—	57 [b]	—	—
Total	$(6)	$—	$1,542	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$ 1,009 [c]
Electric commodity	—	(265)	—	8,631 [d]	—
Natural gas commodity	—	(2,702)	—	11,666 [e]	(5,024) [e]
Total	$—	$ (2,967)	$—	$ 20,297	$ (4,015)

	Three Months Ended March 31, 2015				
	Pre-Tax Fair Value 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	$—	$—	$941 [a]	$—	$—
Vehicle fuel and other commodity	(18)	—	26 [b]	—	—
Total	$(18)	$—	$967	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$ 3,880 [c]

Electric commodity	—	(9,471)	—	(5,123) [d]	—
Natural gas commodity	—	(216)	—	(8,831) [e]	8,991 [e]
Total	$—	$ (9,687)	$—	$ (13,954)	$ 12,871

(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 months ended March 31, 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 months ended March 31, 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 months ended March 31, 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 continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of 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 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.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. At March 31, 2016, one of Xcel Energy's 10 most significant counterparties for these activities, comprising $16.7 million or 7 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 $67.2 million or 30 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 $16.5 million or 7 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 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 March 31, 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 given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of March 31, 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 March 31, 2016:

	March 31, 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	$1,054	$17,417	$453	$18,924	$ (10,970)	$7,954
Electric commodity	—	—	7,879	7,879	(1,443)	6,436
Total current derivative assets	$1,054	$17,417	$8,332	$26,803	$ (12,413)	14,390
PPAs [(a)]						8,903
Current derivative instruments						$23,293
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$250	$35,248	$—	$35,498	$ (8,893)	$26,605
Natural gas commodity	—	9	—	9	—	9
Total noncurrent derivative assets	$250	$35,257	$—	$35,507	$ (8,893)	26,614
PPAs [(a)]						28,998
Noncurrent derivative instruments						$55,612

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(Thousands of Dollars)	March 31, 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	$—	$152	$—	$152	$—	$152
Other derivative instruments:						
Commodity trading	1,334	14,767	35	16,136	(11,805)	4,331
Electric commodity	—	—	1,443	1,443	(1,443)	—
Natural gas commodity	—	119	—	119	—	119
Other commodity	—	92	—	92	—	92
Total current derivative liabilities	$1,334	$15,130	$1,478	$17,942	$(13,248)	4,694
PPAs [a]						22,859
Current derivative instruments						$27,553
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$215	$27,025	$—	$27,240	$(12,497)	$14,743
Natural gas commodity	—	6	—	6	—	6
Total noncurrent derivative liabilities	$215	$27,031	$—	$27,246	$(12,497)	14,749
PPAs [a]						152,550
Noncurrent derivative instruments						$167,299

(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 March 31, 2016. At March 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $4.4 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 months ended March 31, 2016 and 2015:

(Thousands of Dollars)	Three Months Ended March 31 2016	2015
Balance at Jan. 1	$18,028	$56,155
Purchases	1,843	5,792
Settlements	(18,256)	(19,931)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [a]	(24)	60
Gains (losses) recognized as regulatory assets and liabilities	5,263	(24,647)
Balance at March 31	$6,854	$17,429

(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 months ended March 31, 2016 and 2015.

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Fair Value of Long-Term Debt

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

	March 31, 2016		Dec. 31, 2015	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion [(a)]	$13,804,911	$15,410,430	$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 March 31, 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 March 31	
(Thousands of Dollars)	2016	2015
Interest income	$4,070	$4,238
Other nonoperating income	680	968
Insurance policy expense	(500)	(2,045)
Other income, net	$4,250	$3,161

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 $132.8 million and $130.0 million as of March 31, 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 March 31, 2016					
Operating revenues from external customers	$2,185,119	$565,689	$21,465	$ —	$2,772,273
Intersegment revenues	335	287	—	(622)	—
Total revenues	$2,185,454	$565,976	$21,465	$ (622)	$2,772,273
Net income (loss)	$178,237	$78,338	$(15,263)	$ —	$241,312

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2015					
Operating revenues from external customers	$2,224,863	$715,996	$21,360	$ —	$2,962,219
Intersegment revenues	330	676	—	(1,006)	—
Total revenues	$2,225,193	$716,672	$21,360	$ (1,006)	$2,962,219
Net income (loss)	$81,021 [a]	$83,676	$(12,631)	$ —	$152,066

[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.

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.

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

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$241,312	—	—	$152,066	—	—
Basic EPS:						
Earnings available to common shareholders	241,312	508,667	$ 0.47	152,066	506,983	$ 0.30
Effect of dilutive securities:						
Time based equity awards	—	483	—	—	410	—
Diluted EPS:						
Earnings available to common shareholders	$241,312	509,150	$ 0.47	$152,066	507,393	$ 0.30

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31			
	2016	2015	2016	2015
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$22,920	$24,828	$432	$529
Interest cost	40,023	37,131	6,527	6,324
Expected return on plan assets	(52,575)	(53,473)	(6,249)	(6,650)
Amortization of prior service credit	(484)	(451)	(2,672)	(2,672)
Amortization of net loss	24,385	31,288	1,011	1,351
Net periodic benefit cost (credit)	34,269	39,323	(951)	(1,118)
Costs not recognized due to the effects of regulation	(4,452)	(7,496)	—	—
Net benefit cost (credit) recognized for financial reporting	$29,817	$31,827	$(951)	$(1,118)

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 months ended March 31, 2016 and 2015 were as follows:

	Three Months Ended March 31, 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 Jan. 1	$(54,862)	$ 110	$ (55,001)	$(109,753)
Other comprehensive loss before reclassifications	(4)	—	(653)	(657)

Losses reclassified from net accumulated other comprehensive loss	938	—	864	1,802
Net current period other comprehensive income	934	—	211	1,145
Accumulated other comprehensive (loss) income at March 31	$(53,928)	$ 110	$ (54,790)	$(108,608)

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(Thousands of Dollars)	Three Months Ended March 31, 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 (loss) income before reclassifications	(11)	1	—	(10)
Losses reclassified from net accumulated other comprehensive loss	585	—	876	1,461
Net current period other comprehensive income	574	1	876	1,451
Accumulated other comprehensive (loss) income at March 31	$(57,054)	$ 111	$ (49,745)	$(106,688)

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2016 and 2015 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended March 31, 2016		Three Months Ended March 31, 2015	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$ 1,485	(a)	$ 941	(a)
Vehicle fuel derivatives	57	(b)	26	(b)
Total, pre-tax	1,542		967	
Tax benefit	(604)		(382)	
Total, net of tax	938		585	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	1,478	(c)	1,535	(c)
Prior service credit	(64)	(c)	(90)	(c)
Total, pre-tax	1,414		1,445	
Tax benefit	(550)		(569)	
Total, net of tax	864		876	
Total amounts reclassified, net of tax	$ 1,802		$ 1,461	

(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.

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.

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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), 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.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	2016	2015
PSCo	$0.23	$0.22
NSP-Minnesota	0.19	0.16
SPS	0.04	0.04

NSP-Wisconsin	0.03	0.05
Equity earnings of unconsolidated subsidiaries	0.02	0.01
Regulated utility	0.51	0.48
Xcel Energy Inc. and other	(0.03)	(0.02)
Ongoing diluted EPS [a]	0.47	0.46
Loss on Monticello LCM/EPU project	—	(0.16)
GAAP diluted EPS	$0.47	$0.30

[a] Amounts may not add due to rounding.

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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 three months ended March 31, 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 increased $0.01 for the first quarter of 2016 compared to ongoing earnings for the first quarter of 2015, which excludes the 2015 adjustment for a charge related to the NSP-Minnesota Monticello LCM/EPU project. Electric and gas margins rose in the first quarter of 2016 primarily due to an increase in retail electric and natural gas rates across various jurisdictions, non-fuel riders and a reduction in O&M expenses. These positive factors were partially offset by higher depreciation, interest charges, property taxes and the negative impact of weather.

PSCo — PSCo's ongoing earnings increased $0.01 per share for the first quarter of 2016. Ongoing earnings were positively impacted by higher natural gas margins, primarily due to natural gas rate increases, as well as lower O&M expenses, partially offset by higher depreciation.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.03 per share for the first quarter of 2016. Higher electric revenue, primarily due to an electric rate increase in Minnesota (interim, subject to refund), and electric non-fuel riders were partially offset by higher depreciation, property taxes and unfavorable weather. The negative impact of weather was partially mitigated by an electric weather decoupling mechanism, approved in the 2014 Minnesota Multi-Year Electric Rate Case.

SPS — SPS' ongoing earnings were flat for the first quarter of 2016. Lower O&M expenses were offset by higher depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings per share decreased $0.02 for the first quarter of 2016. Electric and natural gas rate increases were more than offset by higher O&M expenses and depreciation.

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 March

	31
2015 GAAP diluted EPS	$ 0.30
Loss on Monticello LCM/EPU project	0.16
2015 ongoing diluted EPS	0.46
Components of change — 2016 vs. 2015	
Higher electric margins [(a)]	0.06
Lower O&M expenses	0.01
Higher natural gas margins [(b)]	0.01
Higher depreciation and amortization	(0.06)
Higher interest charges	(0.01)
Higher taxes (other than income taxes)	(0.01)
Other, net	0.01
2016 GAAP and ongoing diluted EPS	$ 0.47

(a) Reflects $(0.013) attributable to weather.
(b) Reflects $(0.008) attributable to weather.

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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 cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. 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.

There was no impact on sales in the first quarter of 2016 due to THI or CDD. The percentage decrease in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
HDD	(13.3)%	(1.1)%	(11.5)%

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

	Three Months Ended March 31		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
Retail electric	$(0.014)[a]	$(0.001)	$(0.013)
Firm natural gas	(0.012)	(0.004)	(0.008)
Total	$(0.026)	$(0.005)	$(0.021)

[a] Reflects the mitigation of a $0.006 adverse weather impact due to electric sales decoupling at NSP-Minnesota.

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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 March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	1.3 %	(4.2)%	(6.0)%	(7.0)%	(2.7)%
Electric commercial and industrial	(0.6)	(1.2)	0.1	(0.9)	(0.7)
Total retail electric sales	0.1	(2.2)	(1.1)	(2.9)	(1.3)
Firm natural gas sales	1.6	(12.6)	N/A	(14.1)	(4.5)

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	1.4 %	(0.6)%	(0.1)%	(2.3)%	— %
Electric commercial and industrial	(0.6)	(0.8)	0.4	(0.3)	(0.4)
Total retail electric sales	0.1	(0.8)	0.3	(1.0)	(0.3)
Firm natural gas sales	(0.3)	(0.6)	N/A	(1.8)	(0.5)

	Three Months Ended March 31 (Excluding Leap Day) [b]				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential [a]	0.3 %	(1.7)%	(1.2)%	(3.4)%	(1.1)%
Electric commercial and industrial	(1.7)	(1.8)	(0.7)	(1.4)	(1.5)
Total retail electric sales	(1.0)	(1.9)	(0.8)	(2.1)	(1.4)
Firm natural gas sales	(1.4)	(1.7)	N/A	(2.9)	(1.6)

(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 100 basis points.

Weather-normalized Electric Growth (Decline) — Excluding Leap Day

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

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

- SPS' residential sales decline reflects lower use per customer, partially offset by customer additions. Electric 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 decline was primarily attributable to lower use per customer, partially offset by customer additions. C&I electric sales decreased due to lower use by small customers in the sand mining industry. The overall decrease was partially offset by large C&I sales as a result of greater use per customer in the oil and gas industries.

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Weather-normalized Natural Gas Decline — Excluding Leap Day

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

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 March 31	
(Millions of Dollars)	2016	2015
Electric revenues	$2,185	$2,225
Electric fuel and purchased power	(862)	(950)
Electric margin	$1,323	$1,275

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

Electric Revenues

(Millions of Dollars)	Three Months Ended March 31 2016 vs. 2015
Fuel and purchased power cost recovery	$ (80)
Estimated impact of weather	(14)
Trading	(7)
Retail rate increases [a]	40
Transmission revenue	11
Non-fuel riders	7
Weather decoupling-Minnesota	4
Other, net	(1)
Total decrease in electric revenues	$ (40)

[a] Increase is primarily related to the Minnesota Electric Rate Case (interim, subject to refund).

Electric Margin

(Millions of Dollars)	Three Months Ended March 31 2016 vs. 2015
Retail rate increases [a]	$ 40

Fuel handling and procurement	8
Non-fuel riders	7
Weather decoupling-Minnesota	4
Estimated impact of weather	(14)
Other, net	3
Total increase in electric margin	$ 48

[a] Increase is primarily related to the Minnesota Electric Rate Case (interim, subject to refund).

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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 March 31	
(Millions of Dollars)	2016	2015
Natural gas revenues	$566	$716
Cost of natural gas sold and transported	(312)	(472)
Natural gas margin	$254	$244

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 March 31 2016 vs. 2015
Purchased natural gas adjustment clause recovery	$(159)
Estimated impact of weather	(7)
Retail rate increases [a]	13
Other, net	3
Total decrease in natural gas revenues	$(150)

(a) Increase is primarily related to Colorado.

Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31 2016 vs. 2015
Retail rate increases [a]	$ 13
Estimated impact of weather	(7)
Other, net	4
Total increase in natural gas margin	$ 10

(a) Increase is primarily related to Colorado.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $8.4 million, or 1.4 percent, for the first quarter of 2016. The decrease was mainly due to the timing 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 $3.6 million, or 6.7 percent, for the first quarter of 2016. The increase was primarily attributable to higher electric and gas recovery rates at NSP-Minnesota, partially offset 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 $46.9 million, or 17.2 percent, for the first quarter of 2016 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 6.4 percent, for the first quarter of 2016. The increase was due to higher property taxes primarily in Colorado and Minnesota.

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Interest Charges — Interest charges increased $11.5 million, or 7.9 percent, for the first quarter of 2016. The increase was related to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense increased $45.1 million for the first quarter of 2016 compared with the same period in 2015. The increase was primarily due to higher pretax earnings in 2016, partially offset by increased wind production tax credits. The ETR was 34.8 percent for the first quarter of 2016 compared with 35.5 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, 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.

In October 2015, NSP-Minnesota proposed revisions to the Plan. The revised proposal addressed stakeholder recommendations as well as the then final 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. 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 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.

NSP-Minnesota believes this will provide substantial opportunities for the ownership of renewable generation and replacement thermal generation. In January 2016, NSP-Minnesota filed supplemental economic and technical information in support of its revised Plan. While the CPP was subsequently stayed, the filing demonstrated anticipated compliance with the CPP while maintaining reasonable costs for customers. Additionally, NSP-Minnesota responded to MPUC inquiries regarding 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. The MPUC has authorized the DOC to engage an expert to aid in its analysis of PI information provided, the results of which are expected to influence NSP-Minnesota's proposed resource portfolio in its next resource plan. Comments and reply comments on the Plan are due July 8, 2016 and Aug. 12, 2016, respectively. The MPUC is expected to make a decision on the resource plan in late 2016.

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North Dakota Energy Resource Considerations — In February 2014, the NDPSC approved a settlement agreement between NSP-Minnesota and NDPSC Advocacy Staff in resolution of the 2013 North Dakota electric rate case. Among other things, the settlement agreement included a commitment to develop a generation cost allocation mechanism for serving North Dakota customers in a way that reflects North Dakota energy policy. In September 2015, NSP-Minnesota and NDPSC Advocacy Staff partially satisfied this commitment through joint filing of a Negotiated Agreement (NA). On Feb. 22, 2016, NSP-Minnesota filed a Revised Negotiated Agreement (RNA) in order to clarify certain provisions of the NA with respect to potential actions by future commissions and staff and as a result of future new federal regulations. On March 9, 2016, the NDPSC approved the RNA, with key terms including:

- Acceleration of NSP-Minnesota's previous settlement commitment to locate thermal generation in North Dakota from 2036 to by the end of 2025;
- Exclusion of select wind and small solar PPAs from NSP-Minnesota's North Dakota fuel cost rider;
- Continued recovery in North Dakota of six existing biomass PPAs, subject, in part, to refund if NSP-Minnesota fails to achieve its generation commitment by the end of 2025;
- Extension of the current rate moratorium through 2017;
- A rebuttable presumption of prudence for continued use of the 12-coincident peak system allocator through 2025; and,
- Development of a framework to address future generation resources to be filed with the NDPSC by Jan. 1, 2017.

NSP-Minnesota's Petition for an Advance Determination of Prudence — In February 2016, the NDPSC discussed NSP-Minnesota's Petition for an Advance Determination of Prudence (ADP) for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation. In March 2016, the NDPSC voted to dismiss NSP-Minnesota's ADP application without prejudice due to concerns that the resource would not be necessary by the 2019 expected in-service date. The North Dakota portion of the PPA is approximately $1.2 million per year.

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.

Nuclear Regulatory Performance — The NRC has a Reactor Oversight Process that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5). Issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern.

At March 31, 2016, Monticello and PI Unit 1 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections.

Based on a December 2015 shutdown, PI Unit 2 moved from Column 1 to Column 2 (regulatory response) due to a white performance indicator related to the level of unplanned rapid shutdowns of the nuclear reactor, of which only a certain level is allowed per year to remain at the green performance level. Plants in Column 2 are subject to special NRC inspections to review and validate that performance issues or inspection findings have been properly addressed. PI Unit 2 returned to service in late February 2016 after addressing the issues leading to shutdown and will be eligible to return to Column 1 once the performance indicator returns to green, subject to an NRC inspection to close the issue. Depending on the unit's operation in 2016, PI Unit 2 could return to green performance and Column 1 later in 2016.

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 March 2016, NSP-Wisconsin filed a final reconciliation of 2015 actual fuel costs with the PSCW, indicating the total amount to be refunded to customers, including interest, is $9.5 million, and increased the deferral accordingly. NSP-Wisconsin has proposed that the refund liability be used to offset the proposed increase in the 2017 test year rate case. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2016.

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PSCo

Brush, Colo. to Castle Pines, Colo. 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, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. to be placed in service by 2022. The estimated project cost is $178 million. The CPUC's decision requires that project construction begin no earlier than May 2020. On April 29, 2016, PSCo filed a petition with the CPUC to request that construction be allowed to begin in 2017 for the project to be placed in service by 2019.

Boulder, Colo. Municipalization — In November 2011, a ballot measure was passed which authorized the formation and operation of a municipal utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage. In May 2014, the City of Boulder (Boulder) City Council passed an ordinance to establish an electric utility.

In 2013, the CPUC ruled that Boulder may not be the retail service provider to any PSCo customers located outside Boulder city limits unless Boulder can establish that PSCo is unwilling or unable to serve those customers. The CPUC also ruled that it has jurisdiction over the transfer of any facilities to Boulder that currently serve any customers located outside Boulder city limits and will determine separation matters. The CPUC has declared that Boulder must receive CPUC transfer approval prior to any eminent domain actions. Boulder appealed this ruling to the Boulder District Court and in January 2015, the Boulder District Court affirmed the CPUC decision. The Boulder District Court also dismissed a condemnation action that Boulder had filed. The CPUC must complete the separation plan proceeding, outlined below, before Boulder may refile a condemnation proceeding.

In July 2015, Boulder filed an application with the CPUC requesting approval of its proposed separation plan. In August 2015, PSCo filed a motion to dismiss Boulder's separation proposal, arguing Boulder's request was not permissible under Colorado law. In December 2015, the CPUC granted the motion to dismiss the application in part, holding that Boulder had no right to acquire PSCo facilities used exclusively to serve customers located outside Boulder city limits. Other portions of Boulder's application were not dismissed, but are stayed until Boulder supplements its application at which time the CPUC will determine whether the application is complete and a proceeding can continue. The CPUC ordered a discovery process to allow Boulder to obtain technical information regarding the electric system and propose a new separation plan. Boulder is expected to refile its plan later this year. PSCo is also challenging Boulder's 2014 formation of its utility in a case that is now before the Colorado Court of Appeals.

Wind Ownership Proposal — Colorado legislation allows for utilities to own up to 50 percent of new renewable resources without a competitive bidding process if the project can be developed at a reasonable price and demonstrate economic benefit. In April 2016, the CPUC determined that the amount of renewable resources PSCo is eligible to develop under the state legislation is based on renewable resources added to the PSCo system since March 2007.

As a result, in May 2016, PSCo expects to submit a proposal to build, own and operate a 600 MW wind facility at a cost of approximately $1 billion, including transmission investment. 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 standard. PSCo plans to request approval of its application by November 2016, in order to commence the project timely and capture the full production tax credit benefit for customers. If approved by the CPUC, the new facility is projected to go into service in December 2018.

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. Under the proposal a wholly-owned subsidiary of PSCo, PSCo Gas Reserves Company (PGRCo), will be formed to partner with Wexpro Development Company (Wexpro), a subsidiary of Questar Corporation, to acquire, develop and operate natural gas producing properties on a 50/50 joint basis, with production recovered under cost of service pricing through PSCo's Gas Cost Adjustment. If approved, PGRCo could potentially invest up to $500 million in natural gas properties over 10 years.

The requested cost of service pricing formula for PGRCo would include all costs of property acquisition and development. The ROE would be based on PSCo's allowed ROE, adjusted up or down a maximum of 100 basis points, based on the price of gas produced relative to market prices.

If the CPUC approves the framework, PSCo and Wexpro will seek to identify and acquire specific natural gas producing properties that would be beneficial to PSCo's gas customers and seek CPUC approval of these specific investments.

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Key dates in the procedural schedule are as follows:

- Supplemental direct testimony — June 27, 2016;
- Intervenor testimony — Aug. 26, 2016;
- Rebuttal testimony — Oct. 25, 2016;
- Hearings — Dec. 5-9, 2016;
- Statement of position — Jan. 6, 2017; and
- A CPUC decision is anticipated in 2017.

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 the summer of 2016.

SPS

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In June 2015, SPS filed a CCN with the PUCT for the Yoakum County to Texas/New Mexico State line portion of this 345 KV line project and the PUCT approved this CCN in March 2016. This line will connect the TUCO substation near Lubbock, Texas with the Yoakum County substation, continuing on to the Hobbs Plant substation near Hobbs, New Mexico. CCNs for the TUCO to Yoakum County substation segment and for the Texas/New Mexico state line to Hobbs Plant segment are planned to be filed later in 2016. The estimated project cost is $242 million. This line is scheduled to be in service in 2020.

Hobbs Plant Substation to China Draw Substation 345 KV Transmission Line — The Hobbs Plant to China Draw transmission line will connect the Hobbs Plant substation to the China Draw substation near Malaga, N.M. with terminations at a proposed Kiowa substation near Carlsbad, N.M. and at the North Loving substation, near Loving, N.M. In May 2016, SPS expects to file a CCN for this line in New Mexico. The estimated project cost is approximately $163 million. The line is anticipated to be in service in 2018.

Wholesale Customer Participation in Electric Reliability Council of Texas (ERCOT) — In March 2016, the PUCT Staff requested comments on Lubbock Power & Light's (LP&L's) proposal to transition a portion of its load (approximately 430 MW on a peak basis) to the ERCOT in June 2019. LP&L's proposal would result in an approximate seven percent reduction of load in SPS, or a loss of approximately $18 million in wholesale transmission revenue 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 may 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.

Summary of Recent Federal Regulatory Developments

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. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

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FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In March, 2015, FERC upheld the new ROE methodology and denied rehearing. The issue of how to apply the new FERC ROE methodology is being contested in various complaint proceedings. As part of a global settlement approved by the FERC in October 2015, three ROE complaints against SPS were resolved. Two complaints against the MISO Transmission Owners, including NSP-Minnesota and NSP-Wisconsin, are pending FERC action. FERC is not expected to issue orders in any of the litigated ROE complaint proceedings until 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 October 2015, SPS submitted filings to the PUCT, NMPRC and Kansas Corporation Commission (KCC) seeking approval to transfer ownership of SPS’ 345kV transmission assets in Kansas and Oklahoma to XEST at net book value of approximately $103 million. After the proposed asset transfer, the transmission facilities would remain subject to SPP functional control, with revenue requirements recovered through the SPP Tariff. SPS and XEST also proposed to enter into a transmission operation and maintenance agreement (O&M Agreement) under which SPS would operate and maintain the transferred facilities and be reimbursed for providing those services to XEST at cost. Key developments related to the filings are as follows:

- The KCC is expected to issue a decision within 10 months of the October filing;
- The hearings in the NMPRC proceedings are scheduled for August 2016 with a decision expected several months later;
- The hearings in the PUCT proceedings are scheduled for October 2016 with a decision expected several months later;
- In December of 2015, Oklahoma Corporation Commission Staff declined jurisdiction in response to SPS;
- Requests for FERC approval of the asset transfer and O&M Agreement were submitted in January 2016, and requested FERC action by June 30, 2016. Golden Spread Electric Cooperative, Inc. (Golden Spread) protested the FERC asset transfer application; and
- Based on the procedural schedules, and assuming receipt of, the required regulatory approvals, SPS expects the proposed asset transfer would take place no earlier than late 2016 or early 2017.

Formula Rate Treatment of ADIT - In 2015, the MISO Transmission Owners, 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 2015 IRS guidance regarding how ADIT must be reflected in formula rates using future test years and a true-up. The filings are 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. FERC required SPS and PSCo to submit additional information regarding their formula rate changes. 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. FERC action on the NSP-Minnesota and NSP-Wisconsin request for clarification remains pending.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) - SPP and MISO were involved in a long-running dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagreed over MISO’s authority to transmit power between the traditional MISO region in the Midwest and the Entergy system. Several cases were filed with the FERC by MISO and SPP between 2011 and 2014. In June 2014, the FERC set the issues for settlement judge and hearing procedures.

In January 2016, the FERC approved a settlement between SPP, MISO and other parties that resolves various disputed matters and provide a defined settlement compensation plan by MISO to SPP. MISO will pay SPP $16 million for the two-year retroactive period (February 2014 to January 2016) and $16 million annually prospectively starting Feb. 1, 2016, subject to a true-up. In January 2016, SPP filed a proposal regarding distribution of the MISO revenues to SPP members, including SPS. In March 2016, the FERC issued an order rejecting one component of the SPP filing, accepting the remainder of the SPP tariff proposal subject to refund, and setting the filing for settlement judge or hearing procedures. The JOA revenue allocated to SPS under the filed SPP proposal was not expected to be material. Separate settlement discussions are ongoing regarding the April 2014 MISO tariff change filing to recover SPP JOA charges in MISO rates. NSP-Minnesota and NSP-Wisconsin expect to be able to recover any resulting MISO charges in retail rates.

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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 March 31, 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	$ 6,494	$ 1,599	$ 140	$ 10,611
NSP-Minnesota	2	418	—	—	—	418
PSCo	1	105	25	—	—	130
		$ 2,901	$ 6,519	$ 1,599	$ 140	$ 11,159

	Options					
(Thousands of Dollars)	Source of	Maturity Less	Maturity 1 to 3	Maturity 4 to 5	Maturity Greater	Total Futures/

	Fair Value	Than 1 Year	Years	Years	Than 5 Years	Forwards Fair Value
NSP-Minnesota	2	$ (113)	$ —	$ —	$ —	$ (113)

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:

	Three Months Ended March 31	
(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	(869)	3,256
Commodity trading contract additions and changes during period	875	(6,995)
Fair value of commodity trading net contract assets outstanding at March 31	$ 11,046	$ 18,072

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At March 31, 2016, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.2 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.3 million. At March 31, 2015, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.5 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 March 31	VaR Limit	Average	High	Low
2016	$ 0.13	$ 3.00	$ 0.11	$0.19	$0.06
2015	0.47	3.00	0.23	0.32	0.17

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 35 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 March 31, 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 $2.8 million and $9.7 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At March 31, 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 March 31, 2016, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $1.5 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $6.2 million. At March 31, 2015, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $8.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $11.3 million.

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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 March 31, 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 March 31, 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 0.5 percent and 3.3 percent of total assets and liabilities, respectively, measured at fair value at March 31, 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 $8.3 million and $1.5 million of estimated fair values, respectively, for FTRs held at March 31, 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 no Level 3 commodity forwards or options held at March 31, 2016.

Liquidity and Capital Resources

Cash Flows

	Three Months Ended March 31	
(Millions of Dollars)	2016	2015
Cash provided by operating activities	$790	$985

Net cash provided by operating activities decreased $195 million for the three months ended March 31, 2016 compared with the three months ended March 31, 2015. The decrease was primarily due to lower tax refunds received, higher customer refunds in 2016, timing of electric and natural gas incentive recovery, and higher pension contributions, partially offset by rate increases in various jurisdictions.

	Three Months Ended March 31	
(Millions of Dollars)	2016	2015
Cash used in investing activities	$(694)	$(738)

Net cash used in investing activities decreased $44 million for the three months ended March 31, 2016 compared with the three months ended March 31, 2015. The decrease was primarily attributable to higher capital expenditures in 2015 related to the completion of certain transmission projects, partially offset by the impact of insurance proceeds related to Sherco Unit 3 received in 2015.

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(Millions of Dollars)	Three Months Ended March 31 2016	2015
Cash used in financing activities	$(79)	$(194)

Net cash used in financing activities decreased $115 million for the three months ended March 31, 2016 compared with the three months ended March 31, 2015. The decrease was primarily due to 2016 debt issuances, partially offset by higher repayments of short-term debt and dividend payments.

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 law provide the Commodity Futures Trading Commission (CFTC) and the SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation, there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. An entity may deal in utility operations-related swaps and not be required to register as a swap dealer provided that the aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that the entity has not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Xcel Energy’s current and projected swap activity is well below these de minimis thresholds. The law also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy is currently meeting all other reporting requirements.

SPP FTR Margining Requirements — The SPP conducted its first annual FTR auction in the spring of 2014 associated with the implementation of the SPP Integrated Market. The process for transmission owners involves the receipt of Auction Revenue Rights (ARRs) and, if elected by the transmission owner, conversion of those ARRs to firm FTRs. SPP requires that the transmission owner post collateral for the conversion of ARRs to FTRs. At March 31, 2016, SPS had a $7 million letter of credit posted with SPP, which was a reduction from the previous requirement of $36 million.

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 March 31, 2016, approximately $3.9 million of cash was held in these accounts.

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the credit facilities is $2.75 billion and each credit facility terminates in October 2019.

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

As of May 4, 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	$ —	$ 1,000	$ —	$ 1,000
PSCo	700	59	641	1	642
NSP-Minnesota	500	116	384	1	385
SPS	400	114	286	—	286
NSP-Wisconsin	150	4	146	1	147
Total	$ 2,750	$ 293	$ 2,457	$ 3	$ 2,460

[a] These credit facilities expire in October 2019.

[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 March 31, 2016	Twelve Months Ended Dec. 31, 2015
Borrowing limit	$2,750	$2,750
Amount outstanding at period end	183	846
Average amount outstanding	774	601
Maximum amount outstanding	1,183	1,360
Weighted average interest rate, computed on a daily basis	0.73 %	0.48 %
Weighted average interest rate at period end	0.63	0.82

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;
- NSP-Minnesota plans to issue approximately $350 million of first mortgage bonds in the second quarter;
- PSCo plans to issue approximately $250 million of first mortgage bonds in the second quarter; and
- SPS plans to issue approximately $300 million of first mortgage bonds in the third quarter.

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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 year.
- Weather-normalized retail electric utility sales are projected to increase 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 $55 million to $65 million over 2015 levels. The change in the capital rider assumption reflects the transfer of recovery of pipeline system integrity adjustment revenue from the rider to base rates per the CPUC decision in the Colorado natural gas case in late January 2016.
- 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 $5 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.

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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 March 31, 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 believe the implementation of the general ledger modules, which occurred during the period ended March 31, 2016, materially affected its internal control over financial reporting. Xcel Energy also does not expect the implementation of the additional modules to materially affect its internal control over financial reporting.

No other 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 March 31, 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
Jan. 1, 2016 — Jan. 31, 2016 [a]	21,483	$ 36.73	—	—
Feb. 1, 2016 — Feb. 29, 2016	—	—	—	—
March 1, 2016 — March 31, 2016 [b]	18,198	$ 34.75	—	—
Total	39,681		—	—

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

(b) Xcel Energy Inc. withholds stock to satisfy tax withholding obligations on vesting of awards of restricted stock under the Xcel Energy Executive Annual Incentive Award Plan.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference

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 Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, with respect to 2.40 percent Senior Notes, Series due March 15, 2021 (incorporated by reference to the Current Report on Form 8-K filed by Xcel Energy Inc. on March 8, 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 March 31, 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.

May 10, 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)