XCEL ENERGY INC
Form 10-Q
April 27, 2018

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, 2018
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, smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

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 April 23, 2018
Common Stock, $2.50 par value	508,856,950 shares

TABLE OF CONTENTS

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).

Table of Contents

PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

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

	Three Months Ended March 31	
	2018	2017
Operating revenues		
Electric	$2,270	$2,299
Natural gas	662	626
Other	19	21
Total operating revenues	2,951	2,946
Operating expenses		
Electric fuel and purchased power	932	925
Cost of natural gas sold and transported	375	365
Cost of sales — other	8	9
Operating and maintenance expenses	557	580
Conservation and demand side management expenses	71	68
Depreciation and amortization	383	365
Taxes (other than income taxes)	145	142
Total operating expenses	2,471	2,454
Operating income	480	492
Other income, net	1	1
Equity earnings of unconsolidated subsidiaries	6	8
Allowance for funds used during construction — equity	23	14
Interest charges and financing costs		
Interest charges — includes other financing costs of $6 and $6, respectively	171	166
Allowance for funds used during construction — debt	(11)	(7)
Total interest charges and financing costs	160	159
Income before income taxes	350	356
Income taxes	59	117
Net income	$291	$239
Weighted average common shares outstanding:		
Basic	509	508
Diluted	509	509
Earnings per average common share:		
Basic	$0.57	$0.47

Diluted	0.57	0.47
Cash dividends declared per common share	$0.38	$0.36

See Notes to Consolidated Financial Statements

Table of Contents

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

	Three Months Ended March 31	
	2018	2017
Net income	$291	$239
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $0 and $1, respectively	1	1
Derivative instruments:		
Reclassification of losses to net income, net of tax of $0 and $1, respectively	—	1
Other comprehensive income	1	2
Comprehensive income	$292	$241

See Notes to Consolidated Financial Statements

Table of Contents

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

	Three Months Ended March 31	
	2018	2017
Operating activities		
Net income	$291	$239
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	387	369
Nuclear fuel amortization	31	31
Deferred income taxes	59	194
Allowance for equity funds used during construction	(23)	(14)
Equity earnings of unconsolidated subsidiaries	(6)	(8)
Dividends from unconsolidated subsidiaries	9	12
Share-based compensation expense	6	18
Other, net	(1)	4
Changes in operating assets and liabilities:		
Accounts receivable	(71)	3
Accrued unbilled revenues	159	174
Inventories	118	88
Other current assets	1	(77)
Accounts payable	(42)	(144)
Net regulatory assets and liabilities	147	18
Other current liabilities	(17)	(43)
Pension and other employee benefit obligations	(146)	(149)
Change in other noncurrent assets	2	—
Change in other noncurrent liabilities	(17)	3
Net cash provided by operating activities	887	718
Investing activities		
Utility capital/construction expenditures	(883)	(749)
Allowance for equity funds used during construction	23	14
Purchases of investment securities	(185)	(173)
Proceeds from the sale of investment securities	179	168
Investments in unconsolidated subsidiaries and other	(3)	(3)
Other, net	(3)	(5)
Net cash used in investing activities	(872)	(748)
Financing activities		
Proceeds from short-term borrowings, net	211	213
Dividends paid	(175)	(173)
Other	(18)	(21)
Net cash provided by financing activities	18	19
Net change in cash and cash equivalents	33	(11)
Cash and cash equivalents at beginning of period	83	85

Cash and cash equivalents at end of period	$116	$74
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(181)	$(174)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$241	$186
Issuance of common stock for equity awards	20	12

See Notes to Consolidated Financial Statements

Table of Contents

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

	March 31, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$116	$83
Accounts receivable, net	868	797
Accrued unbilled revenues	605	764
Inventories	492	610
Regulatory assets	422	424
Derivative instruments	28	44
Prepaid taxes	63	68
Prepayments and other	188	183
Total current assets	2,782	2,973
Property, plant and equipment, net	34,679	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,404	2,397
Regulatory assets	2,965	3,005
Derivative instruments	49	48
Other	280	278
Total other assets	5,698	5,728
Total assets	$43,159	$43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$457	$457
Short-term debt	1,025	814
Accounts payable	1,027	1,243
Regulatory liabilities	270	239
Taxes accrued	544	448
Accrued interest	147	174
Dividends payable	193	183
Derivative instruments	30	29
Other	429	501
Total current liabilities	4,122	4,088
Deferred credits and other liabilities		
Deferred income taxes	3,905	3,845
Deferred investment tax credits	57	58
Regulatory liabilities	5,141	5,083
Asset retirement obligations	2,504	2,475
Derivative instruments	120	126
Customer advances	200	193

Pension and employee benefit obligations	884	1,042
Other	143	145
Total deferred credits and other liabilities	12,954	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	14,522	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 508,661,859 and 507,762,881 shares outstanding at March 31, 2018 and Dec. 31, 2017, respectively	1,272	1,269
Additional paid in capital	5,903	5,898
Retained earnings	4,510	4,413
Accumulated other comprehensive loss	(124)	(125)
Total common stockholders' equity	11,561	11,455
Total liabilities and equity	$43,159	$43,030

See Notes to Consolidated Financial Statements

6

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in millions, shares 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, 2018 and 2017						
Balance at Dec. 31, 2016	507,223	$1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				239		239
Other comprehensive income					2	2
Dividends declared on common stock				(184)		(184)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			(9)	(1)		(10)
Balance at March 31, 2017	507,763	$1,269	$ 5,873	$ 4,036	$ (108)	$ 11,070
Balance at Dec. 31, 2017	507,763	$1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				291		291
Other comprehensive income					1	1
Dividends declared on common stock				(194)		(194)
Issuances of common stock	921	3	14			17
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			(8)	—		(8)
Balance at March 31, 2018	508,662	$1,272	$ 5,903	$ 4,510	$ (124)	$ 11,561

See Notes to Consolidated Financial Statements

Table of Contents

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, 2018 and Dec. 31, 2017; 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, 2018 and 2017; and its cash flows for the three months ended March 31, 2018 and 2017. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2018 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, 2017 balance sheet information has been derived from the audited 2017 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2017. 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, 2017, filed with the SEC on Feb. 23, 2018. 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, 2017, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Leases — In February 2016, the Financial Accounting Standards Board (FASB) issued Leases, Topic 842 (Accounting Standards Update (ASU) No. 2016-02), which for lessees requires balance sheet recognition of right-of-use assets and lease liabilities for most leases. This guidance will be effective for interim and annual reporting periods beginning after Dec. 15, 2018. Xcel Energy has not yet fully determined the impacts of implementation. However, adoption is expected to occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and proposed in Targeted Improvements, Topic 842 (Proposed ASU 2018-200). As such, agreements entered into prior to Jan. 1, 2019 that are currently considered leases are expected to be recognized on the consolidated balance sheet, including contracts for use of office space, equipment and natural gas storage assets, as well as certain purchased power agreements (PPAs) for natural gas-fueled generating facilities. Xcel Energy expects that similar agreements entered into after Dec. 31, 2018 will generally qualify as leases under the new standard.

Recently Adopted

Revenue Recognition — In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. Xcel Energy implemented the guidance on a modified retrospective basis on Jan. 1, 2018. Results for reporting periods beginning after Dec. 31, 2017 are presented in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. Other than increased disclosures regarding revenues related to contracts with customers, the implementation did not have a significant impact on Xcel Energy's consolidated financial statements. For related disclosures, see Note 14.

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 eliminated the available-for-sale classification for marketable equity securities and also replaced the cost method of accounting for non-marketable equity securities with a model for recognizing impairments and observable price changes. Under the new standard, other than when the consolidation or equity method of accounting is utilized, changes in the fair value of equity securities are recognized in earnings. Xcel Energy implemented the guidance on Jan. 1, 2018. As a result of application of accounting principles for rate regulated entities, changes in the fair value of the securities in the nuclear decommissioning fund, historically classified as available-for-sale, continue to be deferred to a regulatory asset, and the overall adoption impacts were not material.

Table of Contents

Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07), which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment, and the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. Xcel Energy implemented the new guidance on Jan. 1, 2018, and as a result, $6 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated income statement for the three months ended March 31, 2017. Under a practical expedient permitted by the standard, Xcel Energy used benefit cost amounts disclosed for prior periods as the basis for retrospective application.

3. Selected Balance Sheet Data

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$ 921	$ 849
Less allowance for bad debts	(53)	(52)
	$ 868	$ 797

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$ 311	$ 311
Fuel	144	186
Natural gas	37	113
	$ 492	$ 610

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$39,348	$39,016
Natural gas plant	5,855	5,800
Common and other property	2,027	2,013
Plant to be retired [(a)]	11	11
Construction work in progress	2,339	2,087
Total property, plant and equipment	49,580	48,927
Less accumulated depreciation	(15,276)	(15,000)
Nuclear fuel	2,701	2,697
Less accumulated amortization	(2,326)	(2,295)
	$34,679	$34,329

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

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, 2017 appropriately represents, in all material respects, the current status of other income tax matters, and is incorporated herein by reference.

9

Table of Contents

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences:

	Three Months Ended March 31	
	2018	2017
Federal statutory rate	21.0 %	35.0 %
State tax, net of federal tax effect	4.9 %	4.0 %
Increases (decreases) in tax from:		
Wind production tax credits	(6.0)	(4.0)
Regulatory differences - ARAM [(a)]	(5.8)	(0.1)
Regulatory differences - ARAM deferral [(b)]	5.4	—
Regulatory differences - other utility plant items	(1.0)	(0.5)
Other, net	(1.6)	(1.5)
Effective income tax rate	16.9 %	32.9 %

(a) The average rate assumption method (ARAM); a method to flow back excess deferred taxes to customers.

(b) As we receive direction from our regulatory commissions regarding the return of excess deferred taxes (to our customers resulting from the TCJA), the ARAM deferral may decrease during the year, which would result in a reduction to tax expense with a corresponding reduction to revenue.

Federal Audits — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2011	December 2018
2012 - 2013	October 2018
2014	September 2018
2015	September 2019
2016	September 2020

In 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims and in 2015, the IRS forwarded the issue to the Office of Appeals (Appeals). In 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. As of March 31, 2018, the case has been forwarded to the Joint Committee on Taxation.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). After evaluating the proposed adjustment, Xcel Energy filed a protest with the IRS. Xcel Energy anticipates the issue will be forwarded to Appeals. As of March 31, 2018, Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

Table of Contents

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, 2018, Xcel Energy’s earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2012

- In 2016, Minnesota began an audit of years 2010 through 2014. As of March 31, 2018, Minnesota had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. As of March 31, 2018, Wisconsin had not proposed any material adjustments; and
- As of March 31, 2018, there were no other state income tax audits in progress.

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

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

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 21	$ 20
Unrecognized tax benefit — Temporary tax positions	19	19
Total unrecognized tax benefit	$ 40	$ 39

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

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (32)	$ (31)

It is reasonably possible that Xcel Energy’s amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audits resume, the Minnesota and Wisconsin audits progress, and other state audits resume. As the IRS Appeals and Minnesota and Wisconsin audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $26 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, 2018 and Dec. 31, 2017 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2018 or Dec. 31, 2017.

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, 2017, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Table of Contents

Tax Reform — Regulatory Proceedings

The specific impacts of the Tax Cuts and Jobs Act (TCJA) on customer rates are subject to regulatory approval. Each of the states in Xcel Energy's service areas have opened dockets to address the impacts of the TCJA. Xcel Energy has made filings and is working with various stakeholders in its jurisdictions to determine the appropriate treatment for the TCJA.

NSP-Minnesota — The Minnesota Public Utility Commission (MPUC) opened a TCJA docket and issued a request for information on the impacts of the TCJA in January 2018. In March 2018, the Minnesota Department of Commerce (DOC) recommended adjusting rates or implementing refunds for the current tax impacts and incorporating the deferred tax impacts in each utility's next rate case.

In April 2018, NSP-Minnesota filed an update of the estimated impact of the TCJA, which reflected an overall reduction in 2018 revenue requirements of approximately $136 million for electric and $7 million for natural gas. The filing also proposed recommended options for delivering tax reform benefits to customers. The proposed electric options included: customer refunds and rider impacts of $68 million, deferral of $44 million to allow for a rate case stay-out for 2020, acceleration of depreciation for the King coal plant of $22 million and low income program funding of $2 million. The proposed natural gas options included customer refunds and rider impacts of $3 million, with the remaining TCJA benefits deferred to mitigate increased costs in the next natural gas rate case. A MPUC decision is expected later in 2018.

Dockets have also been opened in North Dakota and South Dakota. In February 2018, NSP-Minnesota proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings in both jurisdictions.

NSP-Wisconsin — In January 2018, the Public Service Commission of Wisconsin (PSCW) issued an order requiring public utilities to apply deferred accounting for the impacts of the TCJA. In March 2018, NSP-Wisconsin filed recommended plans for Wisconsin, which for electric operations included an option for an immediate bill credit for a portion of the tax savings in 2018 and 2019, while deferring the remainder until NSP-Wisconsin's 2020 electric rate case. For the natural gas operations, NSP-Wisconsin proposed using the TCJA to reduce the unamortized regulatory asset for the Ashland/Northern States Power Lakefront Superfund Site (the Site) clean-up. A PSCW decision on the regulatory treatment of the TCJA is anticipated later in 2018.

For Michigan, NSP-Wisconsin has reached settlement in its electric rate case, which reflects the impacts of the TCJA, and has proposed customer refunds for natural gas operations.

PSCo — In January 2018, the Colorado Public Utilities Commission (CPUC) opened a statewide TCJA proceeding and ordered deferred accounting for all investor-owned utilities.

- Colorado 2017 Multi-Year Natural Gas Rate Case - In February 2018, the administrative law judge (ALJ) approved PSCo and the CPUC Staff's settlement agreement addressing the TCJA, which includes a $20 million reduction to provisional rates effective March 1, 2018. A final true-up, including any outcomes associated with the statewide proceeding, would provide customers the full net benefit of the TCJA effective January 2018. A CPUC decision is pending.

- Colorado Electric - In April 2018, PSCo, the CPUC Staff and the OCC filed a TCJA settlement agreement with the CPUC that identified a reduction in electric revenue requirements of approximately $101 million for the TCJA in 2018. The settlement recommended a customer refund of $42 million in 2018, with the remainder of $59 million be used to accelerate the amortization of an existing prepaid pension asset. With the dismissal of the 2017 rate case, revisions to the TCJA settlement are required to address the impacts of the TCJA for 2019 until new base rates go into effect in connection with a future electric rate case that PSCo anticipates filing later this summer. A CPUC decision is pending.

SPS — In January 2018, the Public Utility Commission of Texas (PUCT) issued an order requiring utilities to apply deferred accounting for the impacts of the TCJA. In February 2018, SPS filed with the PUCT supplemental testimony, which indicated that the TCJA would reduce revenue requirements by approximately $32 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending Texas electric rate case, as discussed below.

In February 2018, SPS filed with the New Mexico Public Regulation Commission (NMPRC) a preliminary quantification of the impacts of the TCJA on its ongoing New Mexico 2017 electric rate case, which indicated that the TCJA would reduce revenue requirements by approximately $11 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending New Mexico electric rate case, as discussed below.

Table of Contents

Federal Energy Regulatory Commission (FERC) Formula Rates — The FERC has not yet issued guidance on how or when electric utilities should reflect the impacts of the TCJA in FERC jurisdictional wholesale rates. The FERC issued a Notice of Inquiry (NOI) in March 2018 seeking comments on how to reflect the TCJA impacts in wholesale rates, in particular changes to accumulated deferred income taxes and bonus depreciation. Comments for the NOI are due in May 2018. However, FERC-approved formula rates for wholesale customers are generally adjusted on an annual basis for certain changes in rate base and actual operating expenses, including income taxes. As a result, these revenues would be subject to an automatic reduction for the effect of the TCJA corporate tax rate change through the annual true-up process, absent specific FERC action.

NSP-Minnesota and NSP-Wisconsin were parties to a February 2018 FERC filing by certain transmission owner (TO) members of the Midcontinent Independent System Operator, Inc. (MISO) proposing to commence early reductions to transmission formula rates in 2018 for the corporate tax rate impacts of the TCJA. Also in February 2018, PSCo made a filing with FERC similarly requesting early reductions in its transmission and production formula rates in 2018 for corporate tax rate impacts of the TCJA. In March 2018, the FERC issued orders granting MISO TOs and PSCo's waiver requests so that 2018 rates will reflect the lower federal corporate tax rate. For SPS, as a portion of the TCJA tax rate change largely offsets a depreciation rate change that was effective Jan. 1, 2018 in its wholesale production rates, SPS has notified FERC that it will continue to charge production rates established in 2017, subject to refund. SPS' wholesale transmission rates continue to be calculated at the pre-TCJA corporate tax rate, subject to true-up in 2019.

NSP-Minnesota

Pending Regulatory Proceedings — MPUC

GUIC Rider — In February 2018, the MPUC approved a 2017 revenue requirement of approximately $20 million for GUIC investments. New rates went into effect in March 2018. In November 2017, NSP-Minnesota filed the 2018 GUIC rider with the MPUC requesting recovery of approximately $28 million from Minnesota gas utility customers. In March 2018, NSP-Minnesota filed a supplement to the 2018 GUIC rider filing to provide an updated capital forecast and address the impact of the TCJA. The net result decreased NSP-Minnesota's 2018 GUIC revenue requirement to approximately $24 million. The MPUC is currently considering the 2018 petition.

Renewable Energy Standard (RES) Rider — In 2017, NSP-Minnesota filed the 2017 and 2018 RES rider petition with the MPUC, requesting approval of a 2017 over-recovery of approximately $10 million and a 2018 revenue requirement of approximately $11 million. The petition was based on a requested return on equity (ROE) of 10.0 percent and includes costs associated with the Courtenay wind farm and the 1,550 megawatt (MW) wind portfolio, which are offset by production tax credits (PTCs) and proceeds from renewable energy credit (REC) sales. The increase in revenue requirements in 2018 is due to new wind projects entering the construction phase. In February and March 2018, NSP-Minnesota filed supplements to the 2017 and 2018 RES rider petition to provide updated actual results and address TCJA impacts. NSP-Minnesota's revised 2017 refund is approximately $13 million, and the revised 2018 revenue requirement is approximately $23 million. The increase in 2018 revenue requirements from the original request is primarily driven by the TCJA impact on PTCs earned on existing wind asset-related costs. A decision from the MPUC is expected later in 2018.

PSCo

Pending Regulatory Proceedings — CPUC

Colorado 2017 Multi-Year Electric Rate Case — In October 2017, PSCo filed a multi-year request with the CPUC seeking to increase electric rates approximately $245 million over four years. The request was based on forecast test years (FTY), a 10.0 percent ROE and an equity ratio of 55.25 percent. Interim rates, subject to refund and interest, were to be effective on June 1, 2018.

Revenue Request (Millions of Dollars)	2018	2019	2020	2021	Total
Revenue request	$74	$75	$60	$36	$245
Clean Air Clean Jobs Act (CACJA) rider conversion to base rates	90	—	—	—	90
Transmission Cost Adjustment (TCA) rider conversion to base rates	43	—	—	—	43
Total	$207	$75	$60	$36	$378
Expected year-end rate base (billions of dollars)	$6.8	$7.1	$7.3	$7.4	

Table of Contents

In March 2018, PSCo, CPUC Staff and OCC reached a settlement and filed a motion with the CPUC requesting changes to the procedural schedule and scope of the electric case, which included delaying the implementation of provisional rates from June 2018 to January 2019 and requiring PSCo to file updated test year information for 2019-2021 which included the impacts of TCJA. In April 2018, the CPUC denied the motion on procedural grounds and dismissed the electric rate case. PSCo anticipates filing a new electric rate case in the summer of 2018 with new rates expected to be effective in the first quarter of 2019.

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

Revenue Request (Millions of Dollars)	2018	2019	2020	Total
Revenue request	$ 63	$ 33	$ 43	$ 139
Pipeline System Integrity Adjustment (PSIA) rider conversion to base rates [(a)]	—	94	—	94
Total	$ 63	$ 127	$ 43	$ 233
Expected year-end rate base (billions of dollars) [(b)]	$ 1.5	$ 2.3	$ 2.4	

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

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

In October 2017, the CPUC Staff and the OCC recommended a single 2016 historic test year (HTY) based on an average 13-month rate base, and opposed a multi-year request. In addition, they recommended an equity ratio of 48.73 percent and 51.2 percent, respectively, and the existing PSIA rider expire with the 2018 rates rolled into base rates beginning Jan. 1, 2019. Planned investments in 2019 and 2020 would be recoverable through a future rate case. The Staff and OCC provide for a recommended 2018 rate increase of approximately $30 million and $39 million, respectively.

Provisional rates, subject to refund, of $63 million were implemented on Jan. 1, 2018.

On Jan. 31, 2018, the CPUC ordered deferred accounting for the impacts of TCJA and opened a statewide TCJA proceeding, as discussed below. In February 2018, the ALJ approved a settlement agreement between PSCo and the CPUC, which reduced provisional rates by $20 million to address the impacts of the TCJA. The CPUC is expected to rule on the regulatory treatment of the TCJA and the natural gas rate case later in 2018.

On April 20, 2018, PSCo filed for a PSIA extension through 2020 in the event that the CPUC does not adopt its multi-year plan proposal.

SPS

Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $55 million, or 5.8 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on a HTY ended June 30, 2017, a requested ROE of 10.25 percent, an electric rate base of approximately $1.9 billion and an equity ratio of 53.97 percent.

The following table summarizes SPS' rate increase request:

Revenue Request (Millions of Dollars)	
Incremental revenue request	$69
Transmission Cost Recovery Factor (TCRF) rider conversion to base rates [a]	(14)
Net revenue increase request	$55

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

Table of Contents

Key dates in the revised procedural schedule are as follows:

- PUCT Staff direct testimony — May 2, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — May 14, 2018;
- SPS' rebuttal testimony — May 23, 2018; and
- Hearings — June 4 - 14, 2018.

As discussed above, the PUCT has opened a docket on the impact of the TCJA, which may have an impact on this rate case. In February 2018, SPS filed supplemental testimony with the PUCT, which indicated that TCJA would reduce revenue requirements by approximately $32 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the fourth quarter of 2018.

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of $42 million. In 2015, the PUCT approved an overall rate decrease of approximately $4 million, net of rate case expenses. In April 2016, SPS filed an appeal with the Texas State District Court (District Court) challenging the PUCT's order that had denied SPS' request for rehearing on certain items in SPS' Texas 2015 electric rate case related to capital structure, incentive compensation and wholesale load reductions. In 2017, the District Court denied SPS' appeal, and SPS appealed the District Court's decision to the Court of Appeals. A decision is pending.

Pending Regulatory Proceeding — NMPRC

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $43 million. The request is based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017. This rate case also takes into account the decline in sales of 380 MW in 2017 from certain wholesale customers and seeks to adjust the life of SPS' Tolk power plant (Unit 1 from 2042 to 2032 and Unit 2 from 2045 to 2032).

In February 2018, SPS filed supplemental information, which indicated that the TCJA would reduce revenue requirements by approximately $11 million. In addition, SPS requested an increase in the equity ratio of 58 percent and an adjustment to regional transmission revenue for the impacts of TCJA.

On April 13, 2018, the NMPRC Staff, the New Mexico Attorney General (NMAG), and several other parties filed testimony. The recommended ROE's ranged from 9.0 percent to of 9.21 percent, and the recommended equity ratios were 51.0 percent to 53.97 percent.

Table of Contents

The following table summarizes certain parties' recommendations from SPS' request:

Millions of Dollars	NMPRC Staff Testimony	NMAG Testimony
SPS request	$ 43	$ 43
Reduction to request for the impact of the TCJA	(11)	(11)
SPS request, including the impact of the TCJA	32	32
ROE (9.0 percent and 9.21 percent, respectively)	(4)	(6)
Capital structure (52.0 percent and 53.97 percent, respectively)	(7)	(3)
Accelerated depreciation (Tolk plant)	(3)	(3)
Disallow rate case expenses	(2)	(3)
Regional transmission revenue (adjustment for the impact of the TCJA)	—	(3)
Post test year plant (estimated numbers were updated to actual)	(1)	(2)
Other, net	(4)	(5)
Recommended rate increase	$ 11	$ 7

Key dates in the procedural schedule are as follows:

- SPS' rebuttal testimony — May 2, 2018; and
- Hearings — May 15 - 25, 2018.

SPS anticipates a decision and implementation of final rates in the second half of 2018.

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $41 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately $832 million and a future test year ending June 30, 2018. In 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the New Mexico Supreme Court. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — FERC

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

Table of Contents

In September 2016, the FERC approved an ALJ recommendation that MISO TOs be granted a 10.32 percent base ROE using the methodology adopted by FERC in June 2014 (Opinion 531). This ROE would be applicable for the 15-month refund period from Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE would be 10.82 percent, including a 50 basis point adder for RTO membership. Various parties requested rehearing of the September 2016 order. The requests are pending FERC action.

In February 2015, a second complaint seeking to reduce the MISO ROE from 12.38 percent to 8.67 percent prior to any RTO adder was filed, resulting in a second period of potential refunds from Feb. 12, 2015 to May 11, 2016. In June 2016, an ALJ recommended a base ROE of 9.7 percent, applying the FERC Opinion 531 methodology. Various parties filed exceptions to the ALJ recommendation, and FERC action is pending. In April 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated and remanded Opinion 531. It is unclear how the D.C. Circuit's opinion to vacate and remand Opinion 531 will affect the September 2016 FERC order or the timing and outcome of the second ROE complaint.

NSP-Minnesota has recognized a current refund liability consistent with the best estimate of the final ROE for the Feb. 12, 2015 to May 11, 2016 complaint period.

Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT) Upgrade Costs — Under the SPP OATT, costs of participant-funded, or "sponsored," transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately $13 million for these charges. SPP is also billing SPS ongoing charges of approximately $0.5 million per month. SPS is currently seeking recovery of these SPP charges in its pending Texas and New Mexico base rate cases.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC denied SPS' complaint. SPS sought rehearing in April 2018, which is pending FERC action. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

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, 2017, appropriately represent, in all material respects, the current status of commitments and contingent liabilities and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

PPAs

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

The Xcel Energy utility subsidiaries had approximately 3,537 MW of capacity under long-term PPAs as of March 31, 2018 and Dec. 31, 2017, with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through 2041.

Guarantees and Bond Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum guarantee or indemnity amount. As of March 31, 2018 and Dec. 31, 2017, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

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

(Millions of Dollars)	March 31, 2018	Dec. 31, 2017
Guarantees issued and outstanding	$ 18.6	$ 18.8
Current exposure under these guarantees	—	—
Bonds with indemnity protection	51.7	53.1

Other Indemnification Agreements

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

Environmental Contingencies

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

In January 2017, NSP-Wisconsin agreed to remediate the Phase II Project Area (the Sediments), under a settlement agreement with the Environmental Protection Agency. The settlement agreements were approved by the U.S. District Court for the Western District of Wisconsin. NSP-Wisconsin initiated a full scale wet dredge remedy of the Sediments in 2017. Under the current plan, NSP-Wisconsin anticipates completion of restoration activities of the Sediments in 2018 with finalization of Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site) construction and restoration activities in early 2019 although April weather may challenge that schedule. Groundwater treatment activities at the Site will continue.

The current cost estimate for the remediation of the entire site (both Phase I Project Area and the Sediments) is approximately $172 million, of which approximately $139 million has been spent. As of March 31, 2018 and Dec. 31, 2017, NSP-Wisconsin had recorded a total liability of $33 million and $30 million, respectively, for the entire site.

Table of Contents

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period and to apply a three percent carrying cost to the unamortized regulatory asset. In December 2017, the PSCW approved an NSP-Wisconsin natural gas rate case, which included recovery of additional expenses associated with remediating the Site. The annual recovery of MGP clean-up costs increased from $12 million in 2017 to $18 million in 2018.

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017, which involves targeted source removal of impacted soils and historic MGP infrastructure. It is anticipated that remediation activities will be performed in 2018. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until May 31, 2018.

NSP-Minnesota had recorded an estimated liability of $15 million as of March 31, 2018 and $16 million as of Dec. 31, 2017, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately $22 million, of which approximately $7 million has been spent. NSP-Minnesota has deferred Fargo MGP Site costs allocable to the North Dakota jurisdiction, or approximately 88 percent of all remediation costs, as approved by the North Dakota Public Service Commission (NDPSC). In December 2017, NSP-Minnesota filed a request with the MPUC to defer post-2017 MGP remediation expenditures allocable to the Minnesota jurisdiction, including the Fargo MGP site. In March 2018, the DOC recommended that the MPUC deny NSP-Minnesota's deferral request. A MPUC decision is expected mid-2018.

Other MGP, Landfill or Disposal Sites — Xcel Energy is currently involved in investigating and/or remediating several MGP, landfill or other disposal sites. Xcel Energy has identified eleven sites across its service territories in addition to the sites in Ashland and Fargo, where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities. Xcel Energy anticipates that these investigation or remediation activities will continue through at least 2018. Xcel Energy had accrued $4 million as of March 31, 2018 and Dec. 31, 2017 for all of these sites. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

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

e prime, Xcel Energy Inc. and its other affiliates were sued along with several other gas marketing companies. These cases were all consolidated in the U.S. District Court in Nevada. Six of the cases remain active, which includes a multi-district litigation (MDL) matter consisting of a Colorado class (Breckenridge), a Wisconsin class (Arandell Corp.), a Missouri class, a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." In March 2017, summary judgment was granted by the MDL judge in favor of Xcel Energy and e prime in the Sinclair Oil and Farmland cases. In November 2017, the U.S District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs' motions for class certification and remand back to originating courts in these cases were denied in March 2017. Plaintiffs have appealed the summary judgment motions granted in the Farmland and Sinclair Oil cases and the denial of class certification and remand to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). Oral arguments were heard before the Ninth Circuit in February 2018. In March 2018, the Ninth Circuit reversed and remanded the summary judgment in the Farmland case. The Farmland defendants subsequently filed a request for further review by the Ninth Circuit. In light of the decision in the Farmland case, the Sinclair plaintiffs have requested the Ninth Circuit to reverse the grant of summary judgment without hearing. Final rulings on all pending motions and appeals are expected by the end of 2018. Xcel Energy, NSP-Wisconsin and e prime have concluded that a loss is remote.

Line Extension Disputes — In December 2015, Development Recovery Company (DRC) filed a lawsuit in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements entered into by PSCo and various developers. The dispute involved claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so. This claim is substantially similar to the arguments previously raised by DRC. In February 2018, PSCo filed a motion to dismiss. Dates for this proceeding have not been scheduled.

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

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

Short-Term Debt — 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 and term loan agreements. Commercial paper and term loan borrowings outstanding for Xcel Energy were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months	Year Ended

	Ended March 31, 2018	Dec. 31, 2017
Borrowing limit	$3,250	$3,250
Amount outstanding at period end	1,025	814
Average amount outstanding	1,000	644
Maximum amount outstanding	1,197	1,247
Weighted average interest rate, computed on a daily basis	1.93 %	1.35 %
Weighted average interest rate at period end	2.34	1.90

Table of Contents

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, 2018 and Dec. 31, 2017, there were $31 million and $30 million, respectively, of letters of credit outstanding under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

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

As of March 31, 2018, 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.	$ 1,500	$ 898	$ 602
PSCo	700	99	601
NSP-Minnesota	500	25	475
SPS	400	12	388
NSP-Wisconsin	150	22	128
Total	$ 3,250	$ 1,056	$ 2,194

(a) These credit facilities expire in June 2021, with the exception of Xcel Energy Inc.'s $500 million 364-day term loan agreement entered into in December 2017.

(b) Includes outstanding commercial paper, term loan borrowings and letters of credit.

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding as of March 31, 2018 and Dec. 31, 2017.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

Table of Contents

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

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

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

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

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

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

Non-Derivative Instruments Fair Value Measurements

Nuclear Decommissioning Fund

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the decommissioning the Monticello and Prairie Island (PI) nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments. 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 impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Table of Contents

Unrealized gains for the nuclear decommissioning fund were $543 million and $560 million as of March 31, 2018 and Dec. 31, 2017, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $18 million and $7 million as of March 31, 2018 and Dec. 31, 2017, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of March 31, 2018 and Dec. 31, 2017:

	March 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [b]	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$41	$41	$—	$ —	$ —	$41
Commingled funds:						
Non U.S. equities	270	226	—	—	90	316
Emerging market debt funds	157	—	—	—	164	164
Private equity investments	142	—	—	—	198	198
Real estate	118	—	—	—	186	186
Other commingled funds	4	1	—	—	3	4
Debt securities:						
Government securities	78	—	77	—	—	77
U.S. corporate bonds	325	—	321	—	—	321
Non U.S. corporate bonds	55	—	53	—	—	53
Equity securities:						
U.S. equities	278	557	—	—	—	557
Non U.S. equities	153	229	—	—	—	229
Total	$1,621	$1,054	$451	$ —	$ 641	$2,146

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $141 million of equity investments in unconsolidated subsidiaries and $117 million of rabbi trust assets and miscellaneous investments.

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

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Investments Measured at NAV [b]	Total
Nuclear decommissioning fund [a]						
Cash equivalents	$29	$29	$—	$ —	$ —	$29
Commingled funds:						
Non U.S. equities	264	217	—	—	90	307
Emerging market debt funds	156	—	—	—	166	166
Private equity investments	141	—	—	—	198	198
Real estate	131	—	—	—	202	202
Other commingled funds	9	6	—	—	3	9
Debt securities:						
Government securities	68	—	69	—	—	69
U.S. corporate bonds	320	—	322	—	—	322

Non U.S. corporate bonds	50	—	50	—	—	50
Equity securities:						
U.S. equities	271	557	—	—	—	557
Non U.S. equities	152	234	—	—	—	234
Total	$1,591	$1,043	$441	$ —	$ 659	$2,143

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $140 million of equity investments in unconsolidated subsidiaries and $114 million of rabbi trust assets and miscellaneous investments.

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

For the three months ended March 31, 2018 and 2017 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

Table of Contents

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, as of March 31, 2018:

(Millions 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	$ —	$ 9	$ 2	$ 66	$ 77
U.S. corporate bonds	3	87	174	57	321
Non U.S. corporate bonds	—	16	33	4	53
Debt securities	$ 3	$ 112	$ 209	$ 127	$ 451

Rabbi Trusts

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following tables present the cost and fair value of the assets held in rabbi trusts as of March 31, 2018 and Dec. 31, 2017:

	March 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 11	$ 11	$ —	$ —	$ 11
Mutual funds	48	50	—	—	50
Total	$ 59	$ 61	$ —	$ —	$ 61

	Dec. 31, 2017				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 12	$ 12	$ —	$ —	$ 12
Mutual funds	47	50	—	—	50
Total	$ 59	$ 62	$ —	$ —	$ 62

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

Derivative Instruments Fair Value Measurements

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

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

As of March 31, 2018, accumulated other comprehensive losses related to interest rate derivatives included $3 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

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

Table of Contents

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

As of March 31, 2018, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2018. Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three months ended March 31, 2018 and 2017.

As of March 31, 2018, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included immaterial net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

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

The following table details the gross notional amounts of commodity forwards, options and FTRs as of March 31, 2018 and Dec. 31, 2017:

(Amounts in Millions) [a][b]	March 31, 2018	Dec. 31, 2017
Megawatt hours of electricity	60	68
Million British thermal units of natural gas	30	37

[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, 2018 and 2017 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2018				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 3 [b]
Electric commodity	—	(4)	—	3 [c]	—
Natural gas commodity	—	1	—	2 [d]	(2) [d]

Total	$ —	$ (3)	$ —	$ 5	$ 1

24

Table of Contents

(Millions of Dollars)	Three Months Ended March 31, 2017 — Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1 [(a)]	$ —	$ —
Total	$ —	$ —	$ 1	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 1 [(b)]
Electric commodity	—	1	—	(4) [(c)]	—
Natural gas commodity	—	(6)	—	1 [(d)]	(4) [(d)]
Total	$ —	$ (5)	$ —	$ (3)	$ (3)

(a) Amounts are recorded to interest charges.

(b) 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.

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

(d) Certain derivatives are utilized to mitigate natural gas price risk for electric generation and are recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Amounts for the three months ended March 31, 2018 and 2017 included $1 million of settlement losses and $0.9 million of settlement gains, respectively. The remaining derivative settlement gains and losses for the three months ended March 31, 2018 and 2017 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These gains and losses are subject to cost-recovery and reclassified out of income to a regulatory asset or liability, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three months ended March 31, 2018 and 2017. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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

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

Xcel Energy’s utility subsidiaries’ most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities. As of March 31, 2018, five of Xcel Energy’s 10 most significant counterparties for these activities, comprising $70 million or 35 percent of this credit exposure, had investment grade credit ratings from Standard & Poor’s, Moody’s or Fitch Ratings. Four of the 10 most significant counterparties, comprising $27 million or 14 percent of this credit exposure, were not rated by these external agencies, but based on Xcel Energy’s internal analysis, had credit quality consistent with investment grade. The one remaining significant counterparty, comprising of $7 million or 4 percent of this credit exposure, had credit quality less than investment grade based on ratings from external analysis. Nine of these significant counterparties are municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary’s credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies or for cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of March 31, 2018 and Dec. 31, 2017, there were no derivative instruments in a material liability position with such underlying contract provisions.

Table of Contents

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, 2018 and Dec. 31, 2017.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis as of March 31, 2018:

(Millions of Dollars)	March 31, 2018 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$1	$ 22	$ —	$ 23	$ (12)	$ 11
Electric commodity	—	—	13	13	(2)	11
Total current derivative assets	$1	$ 22	$ 13	$ 36	$ (14)	22
PPAs [a]						6
Current derivative instruments						$ 28
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$1	$ 37	$ 8	$ 46	$ (15)	$ 31
Total noncurrent derivative assets	$1	$ 37	$ 8	$ 46	$ (15)	31
PPAs [a]						18
Noncurrent derivative instruments						$ 49

(Millions of Dollars)	March 31, 2018 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$1	$ 19	$ —	$ 20	$ (13)	$7
Electric commodity	—	—	2	2	(1)	1
Total current derivative liabilities	$1	$ 19	$ 2	$ 22	$ (14)	8
PPAs [a]						22
Current derivative instruments						$30
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$2	$ 30	$ —	$ 32	$ (19)	$13
Total noncurrent derivative liabilities	$2	$ 30	$ —	$ 32	$ (19)	13
PPAs [a]						107
Noncurrent derivative instruments						$120

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

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at March 31, 2018. At March 31, 2018, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $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.

Table of Contents

The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis as of Dec. 31, 2017:

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	Fair Value Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$2	$ 22	$ —	$ 24	$ (15)	$ 9
Electric commodity	—	—	32	32	(2)	30
Total current derivative assets	$2	$ 22	$ 32	$ 56	$ (17)	39
PPAs [a]						5
Current derivative instruments						$ 44
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$ 31	$ 5	$ 36	$ (7)	$ 29
Total noncurrent derivative assets	$—	$ 31	$ 5	$ 36	$ (7)	29
PPAs [a]						19
Noncurrent derivative instruments						$ 48

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	Fair Value Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$2	$ 18	$ —	$ 20	$ (15)	$5
Electric commodity	—	—	2	2	(2)	—
Natural gas commodity	—	1	—	1	—	1
Total current derivative liabilities	$2	$ 19	$ 2	$ 23	$ (17)	6
PPAs [a]						23
Current derivative instruments						$29
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$ 24	$ —	$ 24	$ (10)	$14
Total noncurrent derivative liabilities	$—	$ 24	$ —	$ 24	$ (10)	14
PPAs [a]						112
Noncurrent derivative instruments						$126

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

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of $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.

27

Table of Contents

The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2018 and 2017:

(Millions of Dollars)	Three Months Ended March 31 2018	2017
Balance at Jan. 1	$35	$17
Purchases	1	4
Settlements	(12)	(20)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	2	—
Net (losses) gains recognized as regulatory assets and liabilities	(7)	5
Balance at March 31	$19	$6

[(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, 2018 and 2017.

Fair Value of Long-Term Debt

As of March 31, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Millions of Dollars)	March 31, 2018 Carrying Amount	Fair Value	Dec. 31, 2017 Carrying Amount	Fair Value
Long-term debt, including current portion	$14,979	$15,877	$14,976	$16,531

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, 2018 and Dec. 31, 2017, 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:

(Millions of Dollars)	Three Months Ended March 31 2018	2017
Interest income	$5	$ 4
Other nonoperating income	1	4
Benefits non-service cost	(5)	(6)
Insurance policy expense	—	(1)

Other income, net	$1	$ 1

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 $141 million and $140 million as of March 31, 2018 and Dec. 31, 2017, 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.

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 operating and maintenance (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.

Table of Contents

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2018					
Operating revenues from external customers	$ 2,270	$ 662	$ 19	$ —	$ 2,951
Intersegment revenues	—	—	—	—	—
Total revenues	$ 2,270	$ 662	$ 19	$ —	$ 2,951
Net income (loss)	$ 219	$ 95	$ (22)	$ (1)	$ 291

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2017					
Operating revenues from external customers	$ 2,299	$ 626	$ 21	$ —	$ 2,946
Intersegment revenues	—	—	—	—	—
Total revenues	$ 2,299	$ 626	$ 21	$ —	$ 2,946
Net income (loss)	$ 194	$ 63	$ (18)	$ —	$ 239

11. Earnings Per Share

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

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

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

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.

Table of Contents

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

(Amounts in millions, except per share data)	Three Months Ended March 31, 2018 Income	Shares	Per Share Amount	Three Months Ended March 31, 2017 Income	Shares	Per Share Amount
Net income	$291	—	—	$239	—	—
Basic EPS:						
Earnings available to common shareholders	291	509.0	$ 0.57	239	508.3	$ 0.47
Effect of dilutive securities:						
Equity awards	—	0.5	—	—	0.5	—
Diluted EPS:						
Earnings available to common shareholders	$291	509.5	$ 0.57	$239	508.8	$ 0.47

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

(Millions of Dollars)	Three Months Ended March 31 2018 Pension Benefits	2017 Pension Benefits	2018 Postretirement Health Care Benefits	2017 Postretirement Health Care Benefits
Service cost	$24	$24	$ 1	$ 1
Interest cost [a]	33	36	5	6
Expected return on plan assets [a]	(52)	(52)	(6)	(6)
Amortization of prior service credit [a]	(1)	—	(3)	(3)
Amortization of net loss [a]	27	26	2	1
Net periodic benefit cost (credit)	31	34	(1)	(1)
Costs not recognized due to the effects of regulation	—	(4)	—	—
Net benefit cost (credit) recognized for financial reporting	$31	$30	$ (1)	$ (1)

(a) The components of net periodic cost other than the service cost component are included in the line item "other income, net" in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2018, contributions of $150 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2018.

13. Other Comprehensive Loss

Changes in accumulated other comprehensive loss, net of tax, for the three months ended March 31, 2018 and 2017 were as follows:

(Millions of Dollars)	Three Months Ended March 31, 2018 Gains and	Defined Benefit	Total

	Losses on Cash Flow Hedges	Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(58)	$ (67)	$(125)
Losses reclassified from net accumulated other comprehensive loss	—	1	1
Net current period other comprehensive income	—	1	1
Accumulated other comprehensive loss at March 31	$(58)	$ (66)	$(124)

(Millions of Dollars)	Three Months Ended March 31, 2017 Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(51)	$ (59)	$(110)
Losses reclassified from net accumulated other comprehensive loss	1	1	2
Net current period other comprehensive income	1	1	2
Accumulated other comprehensive loss at March 31	$(50)	$ (58)	$(108)

Table of Contents

Reclassifications from accumulated other comprehensive loss for the three months ended March 31, 2018 and 2017 were as follows:

(Millions of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss			
	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017	
Losses on cash flow hedges:				
Interest rate derivatives	$ —	(a)	$ 1	(a)
Total, net of tax	—		1	
Defined benefit pension and postretirement losses:				
Amortization of net loss	1	(b)	2	(b)
Total, pre-tax	1		2	
Tax benefit	—		(1)	
Total, net of tax	1		1	
Total amounts reclassified, net of tax	$ 1		$ 2	

(a) Included in interest charges

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

14. Revenues

Xcel Energy principally generates revenue from the transmission, distribution and sale of electricity and the transportation, distribution and sale of natural gas to wholesale and retail customers. Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue in an amount that corresponds directly to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized. Contract terms are generally short-term in nature, and as such Xcel Energy does not recognize a separate financing component of its collections from customers. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. Xcel Energy's utility subsidiaries recognize sales to both native load and other end use customers on a gross basis in electric revenue and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

Xcel Energy Inc.'s utility subsidiaries have various rate-adjustment mechanisms in place that provide for the recovery of natural gas, electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred. When applicable, under governing regulatory commission rate orders, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met (including collection within 24 months), revenue is recognized equal to the revenue requirement, which may include return on rate base items and incentives. The mechanisms are revised periodically for differences between the total amount collected and the revenue recognized, which may increase or decrease the level of revenue collected from customers. Alternative revenue is recorded on a gross basis and is disclosed separate from revenue from contracts with customers in the period earned.

Table of Contents

In the following tables, revenue is classified by the type of goods/services rendered and market/customer type. The tables also reconcile revenue to the reportable segments.

	Three Months Ended March 31, 2018			
(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$687	$ 390	$ 9	$1,086
Commercial and industrial (C&I)	1,112	207	7	1,326
Other	33	—	1	34
Total retail	1,832	597	17	2,446
Wholesale	188	—	—	188
Transmission	123	—	—	123
Other	39	28	—	67
Total revenue from contracts with customers	2,182	625	17	2,824
Alternative revenue and other	88	37	2	127
Total revenues	$2,270	$ 662	$ 19	$2,951

	Three Months Ended March 31, 2017			
(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$685	$ 374	$ 8	$1,067
C&I	1,148	195	9	1,352
Other	32	—	1	33
Total retail	1,865	569	18	2,452
Wholesale	181	—	—	181
Transmission	121	—	—	121
Other	25	25	—	50
Total revenue from contracts with customers	2,192	594	18	2,804
Alternative revenue and other	107	32	3	142
Total revenues	$2,299	$ 626	$ 21	$2,946

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.

32

Table of Contents

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

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from the most directly comparable measure calculated and presented in accordance with GAAP. Xcel Energy’s management uses non-GAAP measures 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. Non-GAAP financial measures are intended to supplement investors’ understanding of our operating performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies’ similarly titled non-GAAP financial measures.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses and natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas sold and transported are generally recovered through various regulatory recovery mechanisms, and as a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales - other, O&M expenses, conservation and demand side management (DSM) expenses, depreciation and amortization and taxes (other than income taxes).

Table of Contents

Earnings Adjusted for Certain Items (Ongoing Earnings and Diluted EPS)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. 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 these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the three months ended March 31, 2017 and 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Results of Operations

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.

The following table summarizes GAAP and ongoing diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	2018	2017
PSCo	$0.26	$0.22
NSP-Minnesota	0.22	0.19
SPS	0.07	0.05
NSP-Wisconsin	0.06	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility	0.62	0.51
Xcel Energy Inc. and other	(0.05)	(0.04)
Total	$0.57	$0.47

Summary of Earnings

Explanations below exclude the offsetting impacts on sales and income tax expense of the TCJA.

Xcel Energy — Xcel Energy's earnings increased $0.10 per share for the first quarter of 2018. Increased electric and natural gas margins (excluding the impact of the TCJA), which reflect favorable weather compared to last year, timing of O&M expenses and an increased allowance for funds used during construction (AFUDC) were partially offset by higher depreciation and interest expenses.

PSCo — Earnings increased $0.04 per share for the first quarter of 2018. The increase in earnings was driven by higher natural gas margins (due to the impact of an interim rate increase, subject to refund, and favorable weather) and increased AFUDC primarily related to the Rush Creek wind project. These items were partially offset by higher depreciation expense.

NSP-Minnesota — Earnings increased $0.03 per share for the first quarter of 2018. The increase reflects lower O&M expenses and higher natural gas margins due to favorable weather. These positive factors were partially offset by higher depreciation expense due to increased invested capital.

SPS — Earnings increased by $0.02 per share for the first quarter of 2018, largely due to timing of O&M expenses, the favorable impact of weather and lower interest expense.

NSP-Wisconsin — Earnings increased $0.02 per share for the first quarter of 2018. The increase was driven by higher natural gas and electric rates and the impact of favorable weather, partially offset by additional depreciation and amortization expense related to higher invested capital.

Table of Contents

Changes in GAAP and Ongoing Diluted EPS

The following table summarizes significant components contributing to the changes in 2018 EPS compared with the same period in 2017:

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
GAAP and ongoing diluted EPS — 2017	$ 0.47
Components of change — 2018 vs. 2017	
Higher electric margins (excluding TCJA impacts) [(a)]	0.04
Higher natural gas margins (excluding TCJA impacts) [(a)]	0.04
Lower O&M expenses	0.03
Higher AFUDC — equity	0.02
Lower ETR (excluding TCJA impacts) [(a)] [(b)]	0.01
Higher depreciation and amortization	(0.02)
Higher interest charges	(0.01)
Other, net	(0.01)
GAAP and ongoing diluted EPS — 2018	$ 0.57
[(a)] TCJA impact:	
Income tax - rate change	$ 0.10
Electric revenue reductions	(0.08)
Gas revenue reductions	(0.01)
Holding company - interest expense	(0.01)
Total	$ —

[(b)] The ETR includes the impact of an additional $4 million of wind PTCs for the three months ended March 31, 2018, which are largely flowed back to customers through electric margin.

Statement of Income Analysis

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

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

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel

Energy’s more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy’s residential and commercial customers. Industrial customers are less sensitive to weather.

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

Table of Contents

There was no impact on sales for the first quarter of 2018 due to THI or CDD. The percentage increase (decrease) in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
HDD	0.3 %	(14.4)%	16.0 %

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

	Three Months Ended March 31		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
Retail electric	$ 0.003	$ (0.025)	$ 0.028
Firm natural gas	0.003	(0.018)	0.021
Total (before adjustments for decoupling)	$ 0.006	$ (0.043)	$ 0.049
Decoupling – Minnesota	(0.002)	0.008	(0.010)
Total (adjusted for decoupling)	$ 0.004	$ (0.035)	$ 0.039

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2018 compared to the same period in 2017:

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [(a)]	1.5 %	3.7 %	7.7 %	5.4 %	3.5 %
Electric commercial and industrial	1.7	0.4	5.2	4.9	2.3
Total retail electric sales	1.6	1.4	5.8	5.0	2.7
Firm natural gas sales	12.8	17.0	N/A	16.7	14.5

	Three Months Ended March 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	(0.4)%	(1.3)%	1.2 %	(1.3)%	(0.6)%
Electric commercial and industrial	1.6	(0.6)	4.9	4.3	1.8
Total retail electric sales	0.9	(0.8)	4.3	2.5	1.1
Firm natural gas sales	2.0	1.0	N/A	2.1	1.7

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

Weather-normalized Electric Sales Growth (Decline)

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PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the metal mining industries, which were partially reduced by lower use for the small C&I class.

- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in C&I sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in service related industries offset increased sales to large customers in the manufacturing and energy industries.
- SPS' residential sales grew largely due to higher use per customer and customer additions. The increase in C&I sales was driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin's residential sales decline was primarily attributable to lower use per customer partially offset by customer additions. C&I growth was largely due to increased sales to small and large sand mining and energy industry customers.

Table of Contents

Weather-normalized Natural Gas Sales Growth

- Across most service territories, higher natural gas sales reflect an increase in the number of customers combined with increasing customer use.

Electric Revenues and Margin

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

	Three Months Ended March 31	
(Millions of Dollars)	2018	2017
Electric revenues	$2,333	$2,299
Electric fuel and purchased power	(932)	(925)
Electric margin before impact of the TCJA	$1,401	$1,374
Impact of the TCJA (offset as a reduction in income tax expense)	(63)	—
Electric margin	$1,338	$1,374

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, 2018 vs. 2017
Fuel and purchased power cost recovery	$ (12)
Firm wholesale	(7)
Trading	21
Estimated impact of weather, net of Minnesota decoupling	15
Retail rate increase (Wisconsin)	5
Other, net	12
Total increase in electric revenues before impact of the TCJA	$ 34
Impact of the TCJA (offset as a reduction in income tax expense)	(63)
Total decrease in electric revenues	$ (29)

Electric Margin

(Millions of Dollars)	Three Months Ended March 31, 2018 vs. 2017

Firm wholesale	$ (7)
Estimated impact of weather, net of Minnesota decoupling	15
Purchased capacity costs	11
Retail rate increase (Wisconsin)	5
Other, net	3
Total increase in electric margin before impact of the TCJA	$ 27
Impact of the TCJA (offset as a reduction in income tax expense)	(63)
Total decrease in electric margin	$ (36)

Table of Contents

Natural Gas Revenues and Margin

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

	Three Months Ended March 31	
(Millions of Dollars)	2018	2017
Natural gas revenues	$673	$626
Cost of natural gas sold and transported	(375)	(365)
Natural gas margin before impact of the TCJA	$298	$261
Impact of the TCJA (offset as a reduction in income tax expense)	(11)	$—
Natural gas margin	$287	$261

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, 2018 vs. 2017
Estimated impact of weather	$ 15
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)	12
Purchased natural gas adjustment clause recovery	9
Infrastructure and integrity riders	4
Sales growth	2
Other, net	5
Total increase in natural gas revenues before impact of the TCJA	$ 47
Impact of the TCJA (offset as a reduction in income tax expense)	(11)
Total increase in natural gas revenues	$ 36

Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31, 2018 vs. 2017
Estimated impact of weather	$ 15
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)	12
Infrastructure and integrity riders	4

Sales growth	2
Other, net	4
Total increase in natural gas margin before impact of the TCJA	$ 37
Impact of the TCJA (offset as a reduction in income tax expense)	(11)
Total increase in natural gas margin	$ 26

Table of Contents

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $23 million, or 4.0 percent, for the first quarter of 2018, largely reflecting expense timing. The significant changes are summarized in the table below:

(Millions of Dollars)	Three Months Ended March 31, 2018 vs. 2017
Nuclear plant operations and amortization	$ (10)
Plant generation costs	(9)
Other, net	(4)
Total decrease in O&M expenses	$ (23)

- Nuclear plant operations and amortization expenses are lower largely reflecting expense timing, savings initiatives and reduced refueling outage costs.
- Plant generation costs decreased primarily due to the timing of planned maintenance and overhauls at a number of generation facilities.

Conservation and DSM Expenses — Conservation and DSM expenses increased $3 million, or 4.4 percent, for the first quarter of 2018. The increase was primarily due to higher recovery rates for Colorado electric and natural gas sales. Increased participation in Minnesota natural gas conservation programs was partially offset by lower recovery rates. Conservation and DSM expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Depreciation and Amortization — Depreciation and amortization increased $18 million, or 4.9 percent for the first quarter of 2018. The increase was primarily driven by capital expenditures due to planned system investments.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $3 million, or 2.1 percent for the first quarter of 2018. The increase was primarily due to higher property taxes in Colorado.

AFUDC, Equity and Debt — AFUDC increased $13 million for the first quarter of 2018. The increase was primarily due to the Rush Creek wind project in Colorado and other capital investments.

Interest Charges — Interest charges increased $5 million, or 3.0 percent, for the first quarter of 2018. The increase was related to higher debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $58 million for the first quarter of 2018 compared with the same period in 2017. The decrease was primarily driven by a lower federal tax rate due to the TCJA, an increase in wind PTCs, an increase in plant-related regulatory differences related to ARAM and an increase in other tax credits. This was partially offset by the deferral of ARAM. The ETR was 16.9 percent for the first quarter of 2018 compared with 32.9 percent for the same period in 2017. The lower ETR in 2018 is primarily due to the items referenced above. See Note 4.

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, 2017 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

NSP-Minnesota

PPA Terminations and Amendments — In 2017, NSP-Minnesota filed requests with the MPUC and NDPSC to terminate or amend various PPAs to reduce future costs for customers, which are anticipated to result in excess of $600 million in net cost savings to NSP System customers over the next 10 years. In January 2018, the MPUC issued an order approving NSP-Minnesota's petition to terminate the PPAs with Benson Power LLC (Benson) and Laurentian Energy Authority I, LLC (Laurentian), as well as purchase and close the Benson biomass facility. In March 2018, the MPUC denied requests by several parties to reconsider its approval to terminate the Benson and Laurentian PPAs. NSP-Minnesota reached a settlement agreement with the NDPSC Staff which allows for the termination of the PPAs with Benson and Laurentian, as well as the purchase and closure of the Benson biomass facility. A NDPSC decision is anticipated in May 2018.

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation. NSP-Minnesota plans to submit updates including TCJA impacts on the new wind generation to the MPUC and NDPSC in May 2018. The timing of a NDPSC order is uncertain. The regulatory filing updates are not expected to impact the timing of these projects which are expected to be completed by the end of 2020 and qualify for 100 percent of the PTC. NSP-Minnesota's total capital investment for these wind ownership projects is expected to be approximately $1.9 billion.

In 2017, NSP-Minnesota filed with the MPUC seeking approval to build and own the Dakota Range, a 300 MW wind project in South Dakota. The project is expected to be placed into service by the end of 2021 and qualify for 80 percent of the PTC. In March 2018, NSP-Minnesota submitted supplemental filings to the MPUC and NDPSC regarding the impacts of the TCJA and other updated information for Dakota Range. These impacts result in a minimal increase in the revenue requirement for Dakota Range and the project continues to show significant benefits to customers. In April 2018, the MPUC approved NSP-Minnesota's petition to build and own the Dakota Range. A NDPSC decision is pending.

These wind projects are expected to provide significant savings to NSP-Minnesota's customers and substantial environmental benefits. Projected savings/benefits assume fuel costs and generation mix consistent with various commission approved resource plans.

Minnesota State Right-Of-First Refusal (ROFR) Statute Complaint — In September 2017, LSP Transmission Holdings, LLC (LSP Transmission) filed a complaint in the U.S. District Court for the District of Minnesota (Minnesota District Court) against the Minnesota Attorney General, the MPUC and the DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minn. to Winnebago, Minn. The line was estimated by MISO to cost $103 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenges the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. In April 2018, the Antitrust Division of the United States Department of Justice, filed a statement in support of LSP Transmission's position that the statute is unconstitutional. The matter is pending before the Minnesota District Court. The timing and outcome of the litigation is uncertain.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 12 of NSP-Minnesota's Annual Report on Form 10-K for the year ended Dec. 31, 2017 for further discussion regarding the nuclear generating plants. The circumstances set forth in Nuclear Power Operations and Waste Disposal included in

Item 1 of NSP-Minnesota's Annual Report on Form 10-K for the year ended Dec. 31, 2017, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

NSP-Wisconsin

2017 Electric Fuel Cost Recovery — NSP-Wisconsin's electric fuel costs for 2017 were lower than authorized in rates and outside the two percent annual tolerance band, primarily due to lower purchased power costs coupled with moderate weather and generation sales into the MISO market. Under the fuel cost recovery rules, NSP-Wisconsin may retain approximately $4 million of fuel costs and defer the amount of over-recovery in excess of the two percent annual tolerance band for future refund to customers. In March 2018, NSP-Wisconsin filed a reconciliation of 2017 fuel costs with the PSCW indicating a refund liability of approximately $10 million. The final amount of the refund is subject to review and approval by the PSCW, which is expected in mid- 2018.

Table of Contents

PSCo

Colorado Energy Plan (CEP) — In 2016, PSCo filed its 2016 Electric Resource Plan (ERP) which included the estimated need for additional generation resources through spring of 2024. In 2017, PSCo filed an updated capacity need with the CPUC of 450 MW in 2023.

In 2017, PSCo and various other stakeholders filed a stipulation agreement (Stipulation) proposing the CEP, an alternative plan that increases the amount of new renewable resources sought under the ERP. The CEP would increase PSCo's potential capacity need up to 1,110 MW due to the proposed retirement of two coal units. The major components include:

- Early retirement of 660 MWs of coal-fired generation at Comanche Units 1 (2022) and 2 (2025);
- Accelerated depreciation for the early retirement of the two Comanche units and establishment of a regulatory asset to collect the incremental depreciation expense and related costs;
- A request for proposal (RFP) for up to 1,000 MW of wind, 700 MW of solar and 700 MW of natural gas and/or storage;
- Utility ownership targets of 50 percent renewable generation resources and 75 percent of natural gas-fired, storage, or renewable with storage generation resources; and
- Reduction of the renewable energy standard adjustment rider (RESA), from two percent to one percent effective beginning 2021 or 2022.

In March 2018, the CPUC required additional portfolio requirements beyond the terms of the Stipulation. The CPUC requested PSCo to present 750 MW and 1,100 MW portfolios, and to include a least-cost portfolio in addition to the recommended portfolio. They also requested a scenario without the RESA reduction offsetting the cost of accelerated depreciation. The order did not explicitly approve the Stipulation and deferred action on issues such as the treatment of accelerated depreciation which is being addressed in a separate proceeding.

PSCo is currently evaluating bids from a RFP and anticipates filing its recommended portfolios in May 2018. A CPUC decision on the recommended portfolio is anticipated in the summer of 2018.

Mountain West Transmission Group (MWTG) — PSCo, along with nine other electric service providers from the Rocky Mountain region, had considered creating and operating a joint transmission tariff to increase wholesale market efficiency and improve regional transmission planning. The MWTG sought opportunities to reduce customer costs, and maximize resource and electric grid utilization. Negotiations with the SPP commenced in 2017 in order to develop potential terms for participation in the Regional Transmission Organization. As these negotiations developed, PSCo determined that the likely level of benefits was not sufficient to support continued engagement. On April 20, 2018, PSCo notified SPP, regulators and the other MWTG utility members that it was ending its participation in the regional effort.

Public Utility Regulatory Policies Act (PURPA) Enforcement Complaint against CPUC — Sustainable Power Group, LLC (sPower) has proposed to construct 800 MW of solar generation and 700 MW of wind generation in Colorado and is seeking to require PSCo to contract for these resources under PURPA. In 2017, sPower filed a complaint for declaratory and injunctive relief in the United States District Court for the District of Colorado (District Court) requesting that the court find a December 2016 CPUC ruling that a qualifying facility must be a successful bidder in a PSCo resource acquisition bidding process violated PURPA and FERC rules. PSCo intervened in that proceeding and the CPUC filed a motion to dismiss. In June 2017, the United States Magistrate Judge issued a recommendation to the District Court that sPower's complaint be dismissed because sPower failed to establish that it faced a substantial risk of harm. In October 2017, the District Court denied the CPUC's motion to dismiss and instead allowed sPower to file an amended complaint. The case effectively started over, and PSCo intervened. The CPUC filed a motion to dismiss the amended complaint which is currently pending before the District Court. In February 2018, the Magistrate Judge recommended the CPUC motion to dismiss be denied. The CPUC and PSCo filed objections in March 2018. The timing of a resolution in this case is unclear.

OATT Reform — In late March 2018, PSCo filed for changes to its OATT with the FERC. The tariff change would allow large generating interconnection agreements to be suspended only due to a force majeure event and would apply only to new contracts on a prospective basis. In April 2018, certain parties filed comments opposing the PSCo tariff change. FERC action is pending. PSCo has also initiated a larger stakeholder process to achieve broader queue reform and anticipates filing additional tariff changes later in 2018. On April 19, 2018, FERC issued a final rule requiring queue reforms in addition (but generally complimentary) to reforms PSCo already contemplated; compliance tariff filings will be due in third quarter 2018. PSCo currently has more than 22,000 MW of new generator projects in its interconnection queue.

Table of Contents

SPS

Lubbock Power & Light's (LP&L's) Request for Participation in Electric Reliability Council of Texas (ERCOT) — In September 2017, LP&L filed its application with the PUCT and proposed to transition a portion of its load to ERCOT no later than June 2021. As a result of LP&L's proposal, approximately $18 million in wholesale transmission revenue would be reallocated to remaining SPS transmission customers at the time of the load transition. In November 2017, SPS and various other parties, including the PUCT Staff, filed direct testimony in response to LP&L's application. SPS proposed an Interconnection Switching Fee to be determined by the PUCT.

In February 2018, SPS, LP&L, the PUCT Staff and various other parties filed a stipulation that provides SPS' customers with an Interconnection Switching Fee of approximately $24 million to compensate them for the transfer of LP&L's load from SPP to ERCOT. Under the settlement, SPS would allocate the Interconnection Switching Fee to its Texas and New Mexico retail and wholesale transmission customers through a bill credit following LP&L's load transition to ERCOT. The PUCT approved the stipulation in March 2018. LP&L has announced its intention to transfer to ERCOT effective June 1, 2021.

Texas State Right of First Refusal (ROFR) Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of ERCOT, the ROFR to construct new transmission facilities located in the utility's service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas' SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT's order in the Texas State District Court. The appeals have been consolidated and the case is being briefed.

Wind Proposals — In 2017, SPS filed proposals with the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through two wind farms (the Hale wind project in Texas and the Sagamore wind project in New Mexico) for a cost of approximately $1.6 billion. In addition, the proposal includes a purchased power agreement for 230 MW of wind.

In March 2018, the NMPRC approved SPS' request consistent with the terms of SPS' and the parties' modified unanimous settlement. The key terms of the settlement are:

- An investment cap of $1,675 per kilowatt, which is equal to 102.5 percent of the estimated construction costs;
- SPS customers would receive a credit to their bills if actual capacity factors fall below 48 percent;
- SPS customers would receive 100 percent of the federal PTC; and
- SPS will sell the output from the two wind farms into the market and keep the revenue and the grossed-up PTCs during the time the rate case is pending before the wind projects go into base rates. If the market revenue and grossed up PTC value exceeds the estimated revenue requirement, SPS will refund the excess amount to customers as an additional customer protection during the interim period.

In February 2018, SPS and the parties filed an unopposed settlement with the PUCT. The key terms of the settlement are similar to the terms approved by the NMPRC above except that the ratemaking treatment of the market revenues and grossed-up PTCs will be treated in a traditional ratemaking manner and the effective date of the rates in the rate cases placing the wind farms in rates will be 35 days after SPS files the rate cases.

In April 2018, the PUCT requested additional information regarding the settlement. SPS filed a response and the PUCT is scheduled to consider the settlement April 27, 2018.

Table of Contents

Summary of Recent Federal Regulatory Developments

FERC

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

Xcel Energy attempts to mitigate the risk of regulatory penalties through formal training on prohibited practices and a compliance function that reviews interaction with the markets under FERC and Commodity Futures Trading Commission jurisdictions. Public campaigns are conducted to raise awareness of the public safety issues of interacting with our electric systems. While programs to comply with regulatory requirements are in place, there is no guarantee the compliance programs or other measures will be sufficient to ensure against violations.

FERC Order, ROE Policy — In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order (Opinion 531) issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including two ROE complaints involving the MISO TOs, which include NSP-Minnesota and NSP-Wisconsin. In April 2017, the D.C. Circuit vacated and remanded the June 2014 ROE order. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for the NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. The FERC has yet to act on the D.C. Circuit's decision. See Note 5 to the consolidated financial statements for discussion of the D.C. Circuit's decision and the impact on the MISO ROE Complaints.

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