XCEL ENERGY INC
Form 10-Q
October 26, 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 Sept. 30, 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 every Interactive Data File required to be submitted 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 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 ¨
	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	Oct. 19, 2018
Common Stock, $2.50 par value	513,848,752 shares

Table of Contents

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 Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Operating revenues				
Electric	$2,802	$2,784	$7,419	$7,421
Natural gas	227	214	1,181	1,130
Other	19	19	57	58
Total operating revenues	3,048	3,017	8,657	8,609
Operating expenses				
Electric fuel and purchased power	1,040	1,006	2,907	2,850
Cost of natural gas sold and transported	58	64	537	543
Cost of sales — other	9	8	26	25
Operating and maintenance expenses	593	536	1,729	1,688
Conservation and demand side management expenses	77	74	216	206
Depreciation and amortization	440	371	1,199	1,102
Taxes (other than income taxes)	135	134	417	411
Total operating expenses	2,352	2,193	7,031	6,825
Operating income	696	824	1,626	1,784
Other expense (net)	(7)	(1)	(8)	(4)
Equity earnings of unconsolidated subsidiaries	9	7	25	22
Allowance for funds used during construction — equity	30	24	79	54
Interest charges and financing costs				
Interest charges — includes other financing costs of $6, $6, $18 and $18, respectively	177	168	523	498
Allowance for funds used during construction — debt	(13)	(11)	(35)	(25)
Total interest charges and financing costs	164	157	488	473
Income before income taxes	564	697	1,234	1,383
Income taxes	73	205	187	424
Net income	$491	$492	$1,047	$959
Weighted average common shares outstanding:				
Basic	510	509	510	508
Diluted	511	509	510	509

Earnings per average common share:

Basic	$0.96	$0.97	$2.05	$1.89
Diluted	0.96	0.97	2.05	1.88
Cash dividends declared per common share	$0.38	$0.36	$1.14	$1.08

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 Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Net income	$491	$492	$1,047	$959
Other comprehensive income				
Pension and retiree medical benefits:				
Net pension and retiree medical losses arising during the period, net of tax of $(1), $0, $(1), and $0, respectively	(2)	—	(2)	—
Amortization of losses included in net periodic benefit cost, net of tax of $1, $1, $2 and $1, respectively	4	1	6	3
	2	1	4	3
Derivative instruments:				
Reclassification of losses to net income, net of tax of $0, $1, $1 and $2, respectively	1	1	2	2
Other comprehensive income	3	2	6	5
Comprehensive income	$494	$494	$1,053	$964

See Notes to Consolidated Financial Statements

4

Table of Contents

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

	Nine Months Ended Sept. 30	
	2018	2017
Operating activities		
Net income	$1,047	$959
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	1,213	1,113
Nuclear fuel amortization	92	88
Deferred income taxes	184	501
Allowance for equity funds used during construction	(79)	(54)
Equity earnings of unconsolidated subsidiaries	(25)	(22)
Dividends from unconsolidated subsidiaries	27	32
Share-based compensation expense	25	44
Other, net	(16)	(3)
Changes in operating assets and liabilities:		
Accounts receivable	(48)	(31)
Accrued unbilled revenues	114	104
Inventories	37	(9)
Other current assets	52	64
Accounts payable	37	(68)
Net regulatory assets and liabilities	164	(27)
Other current liabilities	(158)	(112)
Pension and other employee benefit obligations	(134)	(135)
Change in other noncurrent assets	12	(15)
Change in other noncurrent liabilities	(51)	(62)
Net cash provided by operating activities	2,493	2,367
Investing activities		
Utility capital/construction expenditures	(2,760)	(2,256)
Allowance for equity funds used during construction	79	54
Purchases of investment securities	(494)	(972)
Proceeds from the sale of investment securities	479	949
Other, net	(10)	(14)
Net cash used in investing activities	(2,706)	(2,239)
Financing activities		
(Repayments of) proceeds from short-term borrowings, net	(376)	122
Proceeds from issuances of long-term debt	1,381	1,422
Repayments of long-term debt, including reacquisition premiums	(301)	(1,030)
Proceeds from issuance of common stock	203	—
Dividends paid	(544)	(538)
Other, net	(20)	(21)
Net cash provided by (used in) financing activities	343	(45)
Net change in cash and cash equivalents	130	83

Cash and cash equivalents at beginning of period	83	84
Cash and cash equivalents at end of period	$213	$167
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(491)	$(489)
Cash (paid) received for income taxes, net	(4)	42
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$328	$269
Issuance of common stock for equity awards	52	23

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)

	Sept. 30, 2018	Dec. 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$213	$83
Accounts receivable, net	856	797
Accrued unbilled revenues	650	764
Inventories	528	610
Regulatory assets	452	424
Derivative instruments	76	44
Prepaid taxes	71	68
Prepayments and other	157	183
Total current assets	3,003	2,973
Property, plant and equipment, net	35,879	34,329
Other assets		
Nuclear decommissioning fund and other investments	2,473	2,397
Regulatory assets	3,166	3,005
Derivative instruments	42	48
Other	272	278
Total other assets	5,953	5,728
Total assets	$44,835	$43,030
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$556	$457
Short-term debt	437	814
Accounts payable	1,189	1,243
Regulatory liabilities	410	239
Taxes accrued	428	448
Accrued interest	158	174
Dividends payable	194	183
Derivative instruments	31	29
Other	435	501
Total current liabilities	3,838	4,088
Deferred credits and other liabilities		
Deferred income taxes	4,119	3,845
Deferred investment tax credits	54	58
Regulatory liabilities	5,161	5,083
Asset retirement obligations	2,572	2,475
Derivative instruments	107	126
Customer advances	200	193

Pension and employee benefit obligations	909	1,042
Other	202	145
Total deferred credits and other liabilities	13,324	12,967
Commitments and contingencies		
Capitalization		
Long-term debt	15,508	14,520
Common stock — 1,000,000,000 shares authorized of $2.50 par value; and 513,298,952 507,762,881 shares outstanding at Sept. 30, 2018 and Dec. 31, 2017, respectively	1,283	1,269
Additional paid in capital	6,125	5,898
Retained earnings	4,876	4,413
Accumulated other comprehensive loss	(119)	(125)
Total common stockholders’ equity	12,165	11,455
Total liabilities and equity	$44,835	$43,030

See Notes to Consolidated Financial Statements

Table of Contents

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS’ EQUITY (UNAUDITED)
(amounts in millions, shares in thousands)

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders’ Equity
Three Months Ended Sept. 30, 2018 and 2017						
Balance at June 30, 2017	507,763	$ 1,269	$ 5,882	$ 4,079	$ (107)	$ 11,123
Net income				492		492
Other comprehensive income					2	2
Dividends declared on common stock				(184)		(184)
Share-based compensation			7	(1)		6
Balance at Sept. 30, 2017	507,763	$ 1,269	$ 5,889	$ 4,386	$ (105)	$ 11,439
Balance at June 30, 2018	508,898	$ 1,272	$ 5,920	$ 4,580	$ (122)	$ 11,650
Net income				491		491
Other comprehensive income					3	3
Dividends declared on common stock				(195)		(195)
Issuances of common stock	4,401	11	197			208
Share-based compensation			8	—		8
Balance at Sept. 30, 2018	513,299	$ 1,283	$ 6,125	$ 4,876	$ (119)	$ 12,165

See Notes to Consolidated Financial Statements

Table of Contents

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

	Common Stock Issued				Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Other Comprehensive Loss	Common Stockholders' Equity
Nine Months Ended Sept. 30, 2018 and 2017						
Balance at Dec. 31, 2016	507,223	$1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				959		959
Other comprehensive income					5	5
Dividends declared on common stock				(552)		(552)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			7	(3)		4
Balance at Sept. 30, 2017	507,763	$1,269	$ 5,889	$ 4,386	$ (105)	$ 11,439
Balance at Dec. 31, 2017	507,763	$1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,047		1,047
Other comprehensive income					6	6
Dividends declared on common stock				(584)		(584)
Issuances of common stock	5,558	14	221			235
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			7	—		7
Balance at Sept. 30, 2018	513,299	$1,283	$ 6,125	$ 4,876	$ (119)	$ 12,165

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 Sept. 30, 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 and nine months ended Sept. 30, 2018 and 2017; and its cash flows for the nine months ended Sept. 30, 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 Sept. 30, 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. Adoption will occur on Jan. 1, 2019 utilizing the practical expedients provided by the standard and included in Targeted Improvements, Topic 842 (ASU No. 2018-11). On Jan. 1, 2019, agreements historically disclosed as operating leases for the use of real estate, equipment and certain fossil-fueled generating facilities operated under purchased power agreements (PPAs) are expected to be recognized on the consolidated balance sheet. Other than first-time recognition of these types of operating leases on the consolidated balance sheet, the implementation is not expected to have a significant impact on Xcel Energy's consolidated financial statements.

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 material impact on Xcel Energy’s consolidated financial statements. For related disclosures, see Note 14 to the consolidated financial statements.

Classification and Measurement of Financial Instruments — In January 2016, the FASB issued Recognition and Measurement of Financial Assets and Financial Liabilities, Subtopic 825-10 (ASU No. 2016-01), which 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 the 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 and $18 million of pension costs were retrospectively reclassified from operating and maintenance expenses to other income, net on the consolidated income statement for the three and nine months ended Sept. 30, 2017, respectively. 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)	Sept. 30, 2018	Dec. 31, 2017
Accounts receivable, net		
Accounts receivable	$909	$ 849
Less allowance for bad debts	(53)	(52)
	$856	$ 797

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Inventories		
Materials and supplies	$267	$ 311
Fuel	151	186
Natural gas	110	113
	$528	$ 610

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Property, plant and equipment, net		
Electric plant	$39,530	$39,016
Natural gas plant	6,036	5,800
Common and other property	2,100	2,013
Plant to be retired [(a)]	337	11
Construction work in progress	3,029	2,087
Total property, plant and equipment	51,032	48,927
Less accumulated depreciation	(15,483)	(15,000)
Nuclear fuel	2,717	2,697
Less accumulated amortization	(2,387)	(2,295)
	$35,879	$34,329

(a) In the third quarter of 2018, the Colorado Public Utilities Commission (CPUC) approved early retirement of PSCo’s Comanche Units 1, 2 and shared Common plant in approximately 2022, 2025 and 2025, respectively. PSCo also expects Craig Unit 1 to be early retired in approximately 2025. 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. 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.

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 Sept. 30		Nine Months Ended Sept. 30	
	2018	2017	2018	2017
Federal statutory rate	21.0 %	35.0 %	21.0 %	35.0 %
State tax (net of federal tax effect)	5.0	4.1	5.0	4.1
Increase (decreases) in tax from:				
Wind production tax credits (PTCs) [(a)]	(2.6)	(4.8)	(4.3)	(4.5)
Regulatory differences - ARAM [(b)]	(5.6)	(0.1)	(5.6)	(0.1)
Regulatory differences - ARAM deferral [(c)]	3.8	—	4.4	—
Regulatory differences - reversal of prior quarters' ARAM deferral [(c)]	(7.0)	—	(3.3)	—
Regulatory differences - other utility plant items	(0.6)	(0.8)	(0.7)	(0.7)
Other (net)	(1.1)	(4.0)	(1.3)	(3.1)
Effective income tax rate	12.9 %	29.4 %	15.2 %	30.7 %

(a) Quarterly PTCs may vary due to production and timing differences. Annual 2018 PTCs are forecasted to exceed 2017.

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

(c) ARAM has been deferred when regulatory treatment has not been established. As Xcel Energy received direction from its regulatory commissions regarding the return of excess deferred taxes to customers, the ARAM deferral was reversed. This resulted 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 - 2014	October 2019
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. In 2017, Xcel Energy and the Office of Appeals (Appeals) reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

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). Xcel Energy filed a protest with the IRS. As of Sept. 30, 2018, the case has been forwarded to Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Sept. 30, 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 Sept. 30, 2018, Minnesota had not proposed any material adjustments;
- In 2016, Wisconsin began an audit of years 2012 and 2013. The audit concluded in the third quarter of 2018 with no material adjustments; and
- As of Sept. 30, 2018, there were no other state income tax audits in progress.

Table of Contents

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

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

(Millions of Dollars)	Sept. 30, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 27	$ 20
Unrecognized tax benefit — Temporary tax positions	11	19
Total unrecognized tax benefit	$ 38	$ 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)	Sept. 30, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$(36)	$ (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 audit resumes, the Minnesota audit progresses, and other state audits resume. As the IRS Appeals and Minnesota audit progress and the IRS audit resumes, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $29 million.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 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 and in Note 5 to the consolidated financial statements to Xcel Energy Inc.’s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on customer rates are subject to regulatory approval. The following details the status of regulatory decisions in each state where Xcel Energy operates.

NSP-Minnesota —
Minnesota — In August 2018, the Minnesota Public Utilities Commission (MPUC) ordered NSP-Minnesota to refund the 2018 impacts of TCJA, including $5 million to natural gas customers and $131 million to electric customers, including low income program funding of $2 million.

NSP-Minnesota — South Dakota — In July 2018, the South Dakota Public Utilities Commission approved a settlement providing a one-time customer refund of $11 million for the 2018 impact of the TCJA, while NSP-Minnesota would retain the benefits of the TCJA in 2019 and 2020 in exchange for a two-year rate case moratorium.

NSP-Minnesota — North Dakota — Natural Gas — In August 2018, NSP-Minnesota and the North Dakota Public Service Commission (NDPSC) Staff reached a TCJA settlement, in which NSP-Minnesota would amortize $1 million annually of the regulatory asset for the remediation of the manufactured gas plant (MGP) site in Fargo, N.D. beginning in 2018, and retain the TCJA savings to approximately offset the MGP amortization expense. The TCJA benefits would be incorporated into a future rate case and the MGP amortization would then be recoverable through the cost of gas rider until fully amortized. A NDPSC decision related to the settlement is expected to be received by the end of 2018. See Note 6 for further discussion of the Fargo, N.D. MGP Site.

NSP-Minnesota — North Dakota — Electric — In October 2018, NSP-Minnesota and the NDPSC Staff reached a settlement which included a one-time customer refund of $10 million for 2018, while NSP- Minnesota would retain the benefits of the TCJA in 2019 and 2020 in exchange for a two-year rate case moratorium. The settlement also includes an earnings sharing provision in which annual weather normalized earnings exceeding an ROE of 9.85 percent are returned to customers.

Table of Contents

A NDPSC decision related to the settlement is expected to be received by the end of 2018 or during the first quarter of 2019.

NSP-Wisconsin — In May 2018, the Public Service Commission of Wisconsin (PSCW) issued its final order which requires customer refunds of $27 million and defers approximately $5 million until NSP-Wisconsin's next rate case proceeding.

NSP-Wisconsin — Michigan — In May 2018, the Michigan Public Service Commission approved electric and natural gas tax reform settlement agreements. Most of the electric TCJA benefits were included in NSP-Wisconsin's recently approved Michigan 2018 electric base rate case. The return of natural gas TCJA benefits is expected to be completed in 2019.

PSCo — Colorado Natural Gas — In February 2018, the administrative law judge (ALJ) recommended approval of PSCo and the CPUC Staff's TCJA settlement agreement which included a $20 million reduction to provisional rates effective March 1, 2018. In September 2018, PSCo submitted a TCJA true-up filing and revised its TCJA benefit estimate to $24 million and requested an equity ratio of 56 percent to offset the negative impact of the TCJA on credit metrics. A decision is expected in the fourth quarter of 2018. The true-up of the estimated TCJA benefit is expected to be retroactive to January 2018.

PSCo — Colorado Electric — In April 2018, PSCo, the CPUC Staff, and the Office of Consumer Counsel (OCC) filed a TCJA settlement agreement for 2018 that included a customer refund of $42 million in 2018, with the remainder of the $59 million of TCJA benefits to be used to accelerate the amortization of an existing prepaid pension asset. In June 2018, the CPUC approved the customer refund of $42 million. In October 2018, the accelerated amortization of the prepaid pension asset was effective by operation of law. For 2019, the expected customer refund is estimated to be $67 million and amortization of the prepaid pension asset is estimated to be $34 million. Impacts of the TCJA for 2020 and beyond are expected to be addressed in a future electric rate case.

SPS — Texas — In June 2018, SPS, the Public Utility Commission of Texas (PUCT) Staff and various intervenors reached a settlement in the Texas electric rate case which included the impacts of the TCJA. The settlement reflects no change in customer rates or refunds and SPS' actual capital structure, which SPS has informed the parties it intends to be up to a 57 percent equity ratio to offset the negative impacts on its credit metrics and potentially its credit ratings. A PUCT decision is expected in the fourth quarter of 2018.

SPS — New Mexico — In September 2018, the New Mexico Public Regulation Commission (NMPRC) issued its final order in SPS' 2017 electric rate case, which included a refund of the 2018 impact of the TCJA.

Other Regulatory Proceedings

NSP-Minnesota

Recently Concluded Regulatory Proceedings — MPUC and the NDPSC

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction, including payments to Benson of $93 million, as well as other transaction costs and future estimated facility removal costs. For Laurentian, a regulatory asset of $109 million was recognized for annual termination payments over six years. The regulatory approvals provide for recovery of the Benson regulatory asset over approximately 10 years, and for recovery of the Laurentian termination payments as they occur, through fuel and purchased energy recovery mechanisms. The termination of the PPAs is expected to save customers over $600 million over the next 10 years.

PSCo

Pending Regulatory Proceedings — CPUC

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 was based on forward test years, a 10.0 percent ROE and an equity ratio of 55.25 percent.
In August 2018, the CPUC issued an interim decision that included application of a 2016 historic test year (HTY), with a 13-month average rate base, an ROE of 9.35 percent, an equity ratio of 54.6 percent and provided no return on the prepaid pension and retiree medical asset. With these adjustments, the total rate increase, prior to TCJA impacts, would be $47 million. PSCo filed an interim rehearing request to preserve its rights and the CPUC decided that any reconsideration can be brought after a final order incorporating TCJA impacts. The CPUC is expected to issue its order on the natural gas rate case and the final decision related to the impacts of the TCJA in the fourth quarter of 2018.

Table of Contents

PSIA Rider
In October 2018, PSCo, CPUC Staff, and the OCC filed a settlement agreement to extend the PSIA rider through 2021. The CPUC is expected to rule on the settlement in the fourth quarter of 2018.

SPS

Pending Regulatory Proceedings — PUCT

Texas 2017 Electric Rate Case — In 2017, SPS filed a $54 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.

In May 2018, SPS filed rebuttal testimony and revised its request to an overall increase in the annual base rate revenue of approximately $32 million, or 5.9 percent, net of the TCJA (after adjusting for a requested 58 percent equity ratio) and other adjustments. This request would be equivalent to approximately $17 million after adjusting for the Transmission Cost Recovery Factor (TCRF) rider.

In June 2018, SPS, the PUCT Staff and various intervenors reached a settlement, which results in no overall change to SPS' revenues after adjusting for the impact of the TCJA and the lower costs of long-term debt.

The following are key terms:

- The ability to use an equity ratio that reflects SPS' actual capital structure, up to 57 percent;
- A 9.5 percent ROE for the calculation of allowance for funds used during construction (AFUDC);
- TCRF rider will remain in effect;
- SPS will accelerate the depreciable lives of Tolk Units 1 and 2 from 2042 and 2045, respectively, to 2037; and
- SPS agrees that it will file its next base rate case no later than Dec. 31, 2019.

A PUCT decision on the settlement is expected in the fourth quarter of 2018.

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

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately $43 million. The request was based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent, a 35 percent federal income tax rate and a rate base of approximately $885 million, including rate base additions through Nov. 30, 2017.

In May 2018, SPS reduced its request to $27 million, net of the TCJA (approximately $11 million, net of the requested higher equity ratio) and other adjustments, based on a requested ROE of 10.25 percent and an equity ratio of 58.0 percent.

In June 2018, the New Mexico Hearing Examiner issued a recommended decision proposing an increase of $12 million, based on a ROE of 9.4 percent and an equity ratio of 53.97 percent. She also denied SPS' requests to shorten depreciation lives related to Tolk Units 1 and 2 and Cunningham Unit 1. The Hearing Examiner rejected intervenor proposals to refund the impacts of the TCJA back to Jan. 1, 2018.

On Sept. 5, 2018, the NMPRC issued its final order resulting in a revenue increase of approximately $8 million, or 2.1 percent, effective Sept. 27, 2018, based on a ROE of 9.1 percent and a 51 percent equity ratio. The NMPRC also ordered a refund of $10 million associated with the TCJA impacts for the retroactive period of Jan. 1, 2018 through Sept. 27, 2018. SPS recorded a regulatory liability of $10 million for the customer refund in the third quarter of 2018. On Sept. 7, 2018, SPS filed an appeal with the NMSC on the grounds that the NMPRC's findings are contrary to the factual record and do not result in just and reasonable rates as required by law. In addition, SPS filed a motion for stay with the NMSC to delay the implementation of the retroactive TCJA refund until the NMSC issues its decision on SPS' appeal of the rate case order. SPS considers the refund illegal primarily because it violates the prohibition on retroactive ratemaking and results in rates that are not just and reasonable. On Sept. 26, 2018, the NMSC granted a temporary stay to delay the implementation of the retroactive refund until further order of the Court.

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.

Table of Contents

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 ended June 30, 2018. In 2017, the NMPRC dismissed SPS' rate case. SPS filed a notice of appeal in the NMSC. A decision is not expected until the second half of 2019.

Pending Regulatory Proceeding — Federal Energy Regulatory Commission (FERC)

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

In 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. 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. 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.

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. In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these charges was remanded to the FERC. As of September 2018, SPS' recovery of these charges (from 2008 through 2016) is being reviewed by the FERC, which is expected to rule in the first quarter of 2019.

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, and the FERC granted a rehearing for purposes of further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. 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 of the consolidated financial statements, 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 and in Notes 5 and 6 to Xcel Energy Inc.'s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, 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

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.

Table of Contents

The Xcel Energy utility subsidiaries had approximately 3,540 Megawatts (MW) of capacity under long-term PPAs as of Sept. 30, 2018 and 3,537 MW as of 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 various 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. Xcel Energy Inc.'s exposure is based upon the net liability under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum guarantee or indemnity amount. As of Sept. 30, 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)	Sept. 30, 2018	Dec. 31, 2017
Guarantees issued and outstanding	$18.1	$ 18.8
Current exposure under these guarantees	—	—
Bonds with indemnity protection	51.1	53.1

Other Indemnification Agreements

Xcel Energy Inc. and its subsidiaries provide indemnifications through various contracts. 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 responsible party for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Site) includes NSP-Wisconsin property, previously operated as a MGP facility, an adjacent city lakeshore park area, and a sediment area of Lake Superior's Chequamegon Bay. NSP-Wisconsin completed wet dredging at the Site in August of 2018 and anticipates completion of final site restoration activities in early 2019. Groundwater treatment activities at the Site will continue for many years.

The current cost estimate for the remediation of the entire site is approximately $184 million, of which approximately $156 million has been spent. As of Sept. 30, 2018 and Dec. 31, 2017, NSP-Wisconsin recorded a total liability of $28 million and $30 million, respectively, for the entire site.

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 — NSP-Minnesota is remediating a former MGP site in Fargo, N.D. Remediation is expected to be completed by early November 2018, and several years of groundwater monitoring is expected to follow. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota has set a trial date for Spring of 2020.

Table of Contents

NSP-Minnesota recorded an estimated liability of $6 million as of Sept. 30, 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 $25 million, of which approximately $19 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 NDPSC. In October 2018, the MPUC denied NSP-Minnesota's request to defer post-2017 MGP remediation expenditures allocable to the Minnesota jurisdiction, including the Fargo MGP Site.

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 Ashland MGP Site and the Fargo MGP Site, 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 2019. Xcel Energy accrued $4 million as of Sept. 30, 2018 and Dec. 31, 2017 for all of these sites. There may be insurance recovery and/or recovery from other responsible parties that will offset any costs incurred.

Environmental Requirements

Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the United States Environmental Protection Agency published a final rule regulating the management, storage, and disposal of coal combustion residuals (CCRs) as a nonhazardous waste (CCR Rule).

Under the CCR Rule, utilities are required to complete certain groundwater sampling around their CCR landfills and surface impoundments. Xcel Energy has identified at least one site in Colorado where there are impoundments and/or landfills present and where a statistically significant increase of certain constituents exist in the groundwater. However, at that location, Xcel Energy has completed removal of CCR from the impoundments. Xcel Energy is currently conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments. Until Xcel Energy completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial position or cash flows. Xcel Energy believes that any associated costs would be recoverable through regulatory mechanisms.

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 seeking monetary damages 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 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). 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, which was denied. Upon Sinclair’s request, the Ninth Circuit reversed and remanded the summary judgment in the Sinclair case. Plaintiffs have asked the lower court to remand the cases back to the court where the actions were originally filed. The defendants have moved for the lower court to issue a renewed summary judgment in the Farmland case. Later in the summer of 2018 the Ninth Circuit also vacated, but did not reverse, the lower court’s denial of class certification. The defendants have drafted a proposal for a renewed denial for the lower court’s consideration. 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. PSCo filed a motion to dismiss this claim, which was granted in May 2018. DRC subsequently filed an appeal to the Colorado Court of Appeals. It is uncertain when a decision will be rendered regarding this appeal.

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 Ended Sept. 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$3,000	$3,250
Amount outstanding at period end	437	814
Average amount outstanding	634	644
Maximum amount outstanding	824	1,247
Weighted average interest rate, computed on a daily basis	2.45 %	1.35 %
Weighted average interest rate at period end	2.57	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 Sept. 30, 2018 and Dec. 31, 2017, there were $49 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 Sept. 30, 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.	$ 1,250	$ 378	$ 872
PSCo	700	10	690
NSP-Minnesota	500	61	439
SPS	400	37	363
NSP-Wisconsin	150	—	150
Total	$ 3,000	$ 486	$ 2,514

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

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

In addition, Xcel Energy Inc. entered into a $500 million 364-day term loan in December 2017. As of Sept. 30, 2018, $250 million of borrowings remain outstanding with no additional borrowing capacity.

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 Sept. 30, 2018 and Dec. 31, 2017.

Long-Term Borrowings

During the nine months ended Sept. 30, 2018, Xcel Energy Inc. and its utility subsidiaries issued the following:

- PSCo issued $350 million of 3.70 percent first mortgage green bonds due June 15, 2028 and $350 million of 4.10 percent first mortgage green bonds due June 15, 2048;
- Xcel Energy Inc. issued $500 million of 4.00 percent senior notes due June 15, 2028; and
- NSP-Wisconsin issued $200 million of 4.20 percent first mortgage bonds due Sept. 1, 2048.

At-The-Market Equity Offering

In September 2018, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $300 million of its common stock through an at-the-market offering (ATM) program in addition to $75 million of equity to be issued through the dividend reinvestment program and benefit programs. As of Sept. 30, 2018, Xcel Energy Inc. had settled 4.2 million shares of common stock with net proceeds of $199.3 million, through the ATM program. In addition, transaction fees of $1.7 million were paid. In October 2018, an additional 0.5 million shares were settled with net proceeds of $25.5 million and transaction fees of $0.2 million.

Table of Contents

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

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

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

Specific valuation methods include the following:

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

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

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

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.

Table of Contents

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 asset class target allocations approved by the MPUC for the 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.

Unrealized gains for the nuclear decommissioning fund were $600 million and $560 million as of Sept. 30, 2018 and Dec. 31, 2017, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $22 million and $7 million as of Sept. 30, 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 Sept. 30, 2018 and Dec. 31, 2017:

	Sept. 30, 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	$33	$33	$—	$ —	$ —	$33
Commingled funds:						
Non U.S. equities	262	196	—	—	91	287
Emerging market debt funds	163	—	—	—	165	165
Private equity investments	170	—	—	—	250	250
Real estate	125	—	—	—	198	198
Debt securities:						
Government securities	76	—	73	—	—	73
U.S. corporate bonds	334	—	330	—	—	330
Non U.S. corporate bonds	56	—	55	—	—	55

Equity securities:						
U.S. equities	258	591	—	—	—	591
Non U.S. equities	156	229	—	—	—	229
Total	$1,633	$1,049	$458	$ —	$ 704	$2,211

(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 $122 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.

21

	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 and nine months ended Sept. 30, 2018 and 2017 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, as of Sept. 30, 2018:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$2	$71	$73
U.S. corporate bonds	13	91	176	50	330
Non U.S. corporate bonds	2	20	28	5	55
Debt securities	$15	$111	$206	$126	$458

Table of Contents

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 Sept. 30, 2018 and Dec. 31, 2017:

	Sept. 30, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$20	$20	$ —	$ —	$ 20
Mutual funds	46	51	—	—	51
Total	$66	$71	$ —	$ —	$ 71

	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 Sept. 30, 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.

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

As of Sept. 30, 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 and nine months ended Sept. 30, 2018 and 2017.

Table of Contents

As of Sept. 30, 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 Sept. 30, 2018 and Dec. 31, 2017:

(Amounts in Millions) [a][b]	Sept. 30, 2018	Dec. 31, 2017
Megawatt hours of electricity	92	68
Million British thermal units of natural gas	42	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 and nine months ended Sept. 30, 2018 and 2017 on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2018				
	Pre-Tax Fair Value (Losses) Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 1 [a]	$ —	$ —
Total	$ —	$ —	$ 1	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 5 [b]
Electric commodity	—	(2)	—	— [c]	—
Natural gas commodity	—	(2)	—	— [d]	— [d]
Total	$ —	$ (4)	$ —	$ —	$ 5

	Nine Months Ended Sept. 30, 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)				Regulatory	

	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 3 [(a)]	$ —	$ —
Total	$ —	$ —	$ 3	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 14 [(b)]
Electric commodity	—	6	—	— [(c)]	—
Natural gas commodity	—	(1)	—	2 [(d)]	(2) [(d)]
Total	$ —	$ 5	$ —	$ 2	$ 12

Table of Contents

	Three Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 2 (a)	$ —	$ —
Total	$ —	$ —	$ 2	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 1 (b)
Electric commodity	—	18	—	(3) (c)	—
Natural gas commodity	—	(2)	—	— (d)	— (d)
Total	$ —	$ 16	$ —	$ (3)	$ 1

	Nine Months Ended Sept. 30, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$ —	$ —	$ 4 (a)	$ —	$ —
Total	$ —	$ —	$ 4	$ —	$ —
Other derivative instruments					
Commodity trading	$ —	$ —	$ —	$ —	$ 8 (b)
Electric commodity	—	17	—	(9) (c)	—
Natural gas commodity	—	(10)	—	1 (d)	(4) (d)
Total	$ —	$ 7	$ —	$ (8)	$ 4

(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 and nine months ended Sept. 30, 2018 included no settlement gains or losses and $1 million of settlement losses, respectively. Amounts for the three and nine months ended Sept. 30, 2017 included no settlement gains or losses and $1 million of settlement gains, respectively. The remaining derivative settlement gains and losses for the three and nine months ended Sept. 30, 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 and nine months ended Sept. 30, 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.

Table of Contents

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 Sept. 30, 2018, five of Xcel Energy's 10 most significant counterparties for these activities, comprising $69 million or 37 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's or Fitch Ratings. Five of the 10 most significant counterparties, comprising $30 million or 16 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. All ten of these significant counterparties are municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies or for cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Sept. 30, 2018 and Dec. 31, 2017, there were no derivative instruments in a material liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 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 Sept. 30, 2018:

	Sept. 30, 2018					
	Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	$1	$ 39	$ 2	$ 42	$ (15)	$ 27
Electric commodity	—	—	44	44	(1)	43
Natural gas commodity	—	2	—	2	—	2
Total current derivative assets	$1	$ 41	$ 46	$ 88	$ (16)	72
PPAs [a]						4
Current derivative instruments						$ 76
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	$—	$ 32	$ 5	$ 37	$ (12)	$ 25
Total noncurrent derivative assets	$—	$ 32	$ 5	$ 37	$ (12)	25
PPAs [a]						17
Noncurrent derivative instruments						$ 42

26

Table of Contents

(Millions of Dollars)	Sept. 30, 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	$ 35	$ 2	$ 38	$ (28)	$10
Electric commodity	—	—	1	1	(1)	—
Total current derivative liabilities	$1	$ 35	$ 3	$ 39	$ (29)	10
PPAs [a]						21
Current derivative instruments						$31
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$ 23	$ —	$ 23	$ (13)	$10
Total noncurrent derivative liabilities	$—	$ 23	$ —	$ 23	$ (13)	10
PPAs [a]						97
Noncurrent derivative instruments						$107

(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 is being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2018. At Sept. 30, 2018, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $14 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	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

27

Table of Contents

(Millions of Dollars)	Dec. 31, 2017 Fair Value Level 1	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 is being 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.

The following table presents the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2018 and 2017:

(Millions of Dollars)	Three Months Ended Sept. 30 2018	2017
Balance at July 1	$64	$69
Purchases	3	—
Settlements	(19)	(33)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	—	1
Net gains recognized as regulatory assets and liabilities	—	29
Balance at Sept. 30	$48	$66

Nine Months Ended

	Sept. 30	
(Thousands of Dollars)	2018	2017
Balance at Jan. 1	$35	$17
Purchases	49	80
Settlements	(51)	(75)
Net transactions recorded during the period:		
Gains recognized in earnings [a]	—	6
Net gains recognized as regulatory assets and liabilities	15	38
Balance at Sept. 30	$48	$66

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

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2018 and 2017.

Table of Contents

Fair Value of Long-Term Debt

As of Sept. 30, 2018 and Dec. 31, 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Millions of Dollars)	Sept. 30, 2018 Carrying Amount	Sept. 30, 2018 Fair Value	Dec. 31, 2017 Carrying Amount	Dec. 31, 2017 Fair Value
Long-term debt, including current portion	$16,064	$16,485	$14,977	$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 Sept. 30, 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 Expense, Net

Other expense, net consisted of the following:

(Millions of Dollars)	Three Months Ended Sept. 30 2018	Three Months Ended Sept. 30 2017	Nine Months Ended Sept. 30 2018	Nine Months Ended Sept. 30 2017
Interest income	$4	$6	$11	$12
Other nonoperating income	—	—	2	5
Insurance policy expense	—	(1)	(1)	(3)
Benefits non-service costs	(11)	(6)	(20)	(18)
Other expense, net	$(7)	$(1)	$(8)	$(4)

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 $140 million as of both Sept. 30, 2018 and Dec. 31, 2017, included in the regulated natural gas utility segment.

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

Table of Contents

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common 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.

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2018					
Operating revenues from external customers	$ 2,802	$ 227	$ 19	$ —	$ 3,048
Intersegment revenues	—	—	—	—	—
Total revenues	$ 2,802	$ 227	$ 19	$ —	$ 3,048
Net income (loss)	$ 514	$ 9	$ (32)	$ —	$ 491

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2017					
Operating revenues from external customers	$ 2,784	$ 214	$ 19	$ —	$ 3,017
Intersegment revenues	—	—	—	—	—
Total revenues	$ 2,784	$ 214	$ 19	$ —	$ 3,017
Net income (loss)	$ 503	$ 2	$ (13)	$ —	$ 492

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2018					
Operating revenues from external customers	$ 7,419	$ 1,181	$ 57	$ —	$ 8,657
Intersegment revenues	1	1	—	(2)	—
Total revenues	$ 7,420	$ 1,182	$ 57	$ (2)	$ 8,657
Net income (loss)	$ 997	$ 130	$ (80)	$ —	$ 1,047

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2017					
Operating revenues from external customers	$ 7,421	$ 1,130	$ 58	$ —	$ 8,609
Intersegment revenues	1	1	—	(2)	—
Total revenues	$ 7,422	$ 1,131	$ 58	$ (2)	$ 8,609
Net income (loss)	$ 925	$ 78	$ (44)	$ —	$ 959

11. Earnings Per Share

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

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

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

Table of Contents

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

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

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

	Three Months Ended Sept. 30, 2018			Three Months Ended Sept. 30, 2017		
(Amounts in millions, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$491	—	—	$492	—	—
Basic EPS:						
Earnings available to common shareholders	491	510.4	$ 0.96	492	508.6	$ 0.97
Effect of dilutive securities:						
Equity awards	—	0.4	—	—	0.6	—
Diluted EPS:						
Earnings available to common shareholders	$491	510.8	$ 0.96	$492	509.2	$ 0.97

	Nine Months Ended Sept. 30, 2018			Nine Months Ended Sept. 30, 2017		
(Amounts in millions, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$1,047	—	—	$959	—	—
Basic EPS:						
Earnings available to common shareholders	1,047	509.7	$ 2.05	959	508.5	$ 1.89
Effect of dilutive securities:						
Equity awards	—	0.4	—	—	0.6	—
Diluted EPS:						
Earnings available to common shareholders	$1,047	510.1	$ 2.05	$959	509.1	$ 1.88

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2018	2017	2018	2017
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$24	$23	$ 1	$ 1
Interest cost [(a)]	33	37	5	6
Expected return on plan assets [(a)]	(52)	(52)	(6)	(6)
Amortization of prior service credit [(a)]	(1)	(1)	(3)	(3)

Amortization of net loss [a]	27	27	2	1
Settlement charge [b]	59	—	—	—
Net periodic benefit cost (credit)	90	34	(1)	(1)
(Costs) credits not recognized due to the effects of regulation	(50)	(4)	1	—
Net benefit cost (credit) recognized for financial reporting	$40	$30	$ —	$ (1)

Table of Contents

(Millions of Dollars)	Nine Months Ended Sept. 30			
	2018	2017	2018	2017
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 71	$ 71	$ 1	$ 1
Interest cost [(a)]	100	110	16	18
Expected return on plan assets [(a)]	(157)	(157)	(19)	(18)
Amortization of prior service credit [(a)]	(3)	(1)	(8)	(8)
Amortization of net loss [(a)]	83	80	6	5
Settlement charge [(b)]	59	—	—	—
Net periodic benefit cost (credit)	153	103	(4)	(2)
(Costs) credits not recognized due to the effects of regulation	(51)	(12)	1	—
Net benefit cost (credit) recognized for financial reporting	$ 102	$ 91	$ (3)	$ (2)

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

(b) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In the third quarter of 2018 as a result of lump-sum distributions during the 2018 plan year, Xcel Energy recorded a total pension settlement charge of $59 million, the majority of which was not recognized due to the effects of regulation. A total of $6 million of that amount was recorded in other expense in the third quarter of 2018. In the fourth quarter of 2017 as a result of lump-sum distributions during the 2017 plan year, Xcel Energy recorded a total pension settlement charge of $81 million, the majority of which was not recognized due to the effects of regulation. A total of $8 million of that amount was expensed in the fourth quarter of 2017.

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 and nine months ended Sept. 30, 2018 and 2017 were as follows:

(Millions of Dollars)	Three Months Ended Sept. 30, 2018		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at June 30	$ (57)	$ (65)	$ (122)
Other comprehensive loss before reclassifications	—	(2)	(2)
Losses reclassified from net accumulated other comprehensive loss	1	4	5
Net current period other comprehensive income	1	2	3
Accumulated other comprehensive loss at Sept. 30	$ (56)	$ (63)	$ (119)

Table of Contents

(Millions of Dollars)	Three Months Ended Sept. 30, 2017		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at June 30	$(50)	$ (57)	$(107)
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 Sept. 30	$(49)	$ (56)	$(105)

(Millions of Dollars)	Nine Months Ended Sept. 30, 2018		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(58)	$ (67)	$(125)
Other comprehensive loss before reclassifications	—	(2)	(2)
Losses reclassified from net accumulated other comprehensive loss	2	6	8
Net current period other comprehensive income	2	4	6
Accumulated other comprehensive loss at Sept. 30	$(56)	$ (63)	$(119)

(Millions of Dollars)	Nine Months Ended Sept. 30, 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	2	3	5
Net current period other comprehensive income	2	3	5
Accumulated other comprehensive loss at Sept. 30	$(49)	$ (56)	$(105)

Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2018 and 2017 were as follows:

Amounts Reclassified from Accumulated Other Comprehensive Loss

(Millions of Dollars)	Three Months Ended Sept. 30, 2018	Three Months Ended Sept. 30, 2017
Losses on cash flow hedges:		
Interest rate derivatives	$ 1 (a)	$ 2 (a)
Total, pre-tax	1	2
Tax benefit	—	(1)
Total, net of tax	1	1
Defined benefit pension and postretirement losses:		
Amortization of net loss	6 (b)	2 (b)
Total, pre-tax	6	2
Tax benefit	(2)	(1)
Total, net of tax	4	1
Total amounts reclassified, net of tax	$ 5	$ 2

Table of Contents

(Millions of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Nine Months Ended Sept. 30, 2018		Nine Months Ended Sept. 30, 2017	
Losses on cash flow hedges:				
Interest rate derivatives	$ 3	(a)	$ 4	(a)
Total, pre-tax	3		4	
Tax benefit	(1)		(2)	
Total, net of tax	2		2	
Defined benefit pension and postretirement losses:				
Amortization of net loss	8	(b)	5	(b)
Total, pre-tax	8		5	
Tax benefit	(2)		(2)	
Total, net of tax	6		3	
Total amounts reclassified, net of tax	$ 8		$ 5	

(a) Included in interest charges

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

14. Revenues

Xcel Energy principally generates revenue from the generation, 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 revenues 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 Sept. 30, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$890	$ 116	$ 10	$1,016
Commercial and industrial (C&I)	1,408	58	5	1,471
Other	35	—	1	36
Total retail	2,333	174	16	2,523
Wholesale	207	—	—	207
Transmission	143	—	—	143
Other	17	25	—	42
Total revenue from contracts with customers	2,700	199	16	2,915
Alternative revenue and other	102	28	3	133
Total revenues	$2,802	$ 227	$ 19	$3,048

	Three Months Ended Sept. 30, 2017			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$835	$ 114	$ 10	$959
C&I	1,445	59	6	1,510
Other	36	—	1	37
Total retail	2,316	173	17	2,506
Wholesale	194	—	—	194
Transmission	136	—	—	136
Other	31	20	—	51
Total revenue from contracts with customers	2,677	193	17	2,887
Alternative revenue and other	107	21	2	130
Total revenues	$2,784	$ 214	$ 19	$3,017

	Nine Months Ended Sept. 30, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$2,255	$663	$ 28	$2,946
C&I	3,726	347	17	4,090
Other	101	—	5	106
Total retail	6,082	1,010	50	7,142
Wholesale	589	—	—	589
Transmission	398	—	—	398

Other	80	76	—	156
Total revenue from contracts with customers	7,149	1,086	50	8,285
Alternative revenue and other	270	95	7	372
Total revenues	$7,419	$1,181	$ 57	$8,657

Table of Contents

(Millions of Dollars)	Nine Months Ended Sept. 30, 2017 Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$2,174	$651	$ 27	$2,852
C&I	3,836	339	19	4,194
Other	101	—	4	105
Total retail	6,111	990	50	7,151
Wholesale	547	—	—	547
Transmission	383	—	—	383
Other	83	68	—	151
Total revenue from contracts with customers	7,124	1,058	50	8,232
Alternative revenue and other	297	72	8	377
Total revenues	$7,421	$1,130	$ 58	$8,609

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. The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy’s operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

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: changes in environmental laws and regulations; unusual weather and climate change, including compliance with any accompanying legislative and regulatory changes; ability of subsidiaries to recover costs from customers; actions of credit rating agencies; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force factors.

Table of Contents

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).

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 and nine months ended Sept. 30, 2018 and 2017, 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 Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2018	2017	2018	2017
PSCo	$0.41	$0.37	$0.91	$0.78

NSP-Minnesota	0.39	0.45	0.79	0.81
SPS	0.16	0.13	0.34	0.25
NSP-Wisconsin	0.06	0.04	0.15	0.12
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility [a]	1.03	1.00	2.22	1.98
Xcel Energy Inc. and other	(0.07)	(0.03)	(0.17)	(0.10)
Total	$0.96	$0.97	$2.05	$1.88

[a] Amounts may not add due to rounding.

37

Table of Contents

Summary of Earnings

Explanations for operating company results below exclude the offsetting impacts on sales, depreciation and amortization expense and income tax expense of the TCJA.

Xcel Energy — Xcel Energy's earnings decreased $0.01 per share for the third quarter of 2018 and increased $0.17 per share year-to-date. Earnings for the third quarter of 2018 were lower as increased electric and natural gas margins (excluding the impact of the TCJA) which reflects favorable weather compared to last year and sales growth, and increased allowance for funds used during construction (AFUDC), were offset by higher depreciation expenses, operating and maintenance (O&M) expenses and interest expense.

PSCo — Earnings increased $0.04 per share for the third quarter of 2018 and increased $0.13 per share year-to-date. The year-to-date increase in earnings was driven by higher natural gas margins largely due to the impact of a natural gas rate increase, higher electric margins reflecting favorable weather and sales growth, and increased AFUDC primarily related to the Rush Creek wind project. These items were partially offset by higher O&M expenses, interest charges, depreciation expense and property taxes.

NSP-Minnesota — Earnings decreased $0.06 per share for the third quarter of 2018 and decreased $0.02 per share year-to-date. The year-to-date decrease reflects higher depreciation expense due to increased invested capital and O&M expenses, partially offset by higher electric and natural gas margins due to favorable weather.

SPS — Earnings increased by $0.03 per share for the third quarter of 2018 and increased $0.09 per share year-to-date. The year-to-date increase was primarily due to higher electric margins reflecting favorable weather and sales growth, AFUDC related to the Hale County wind project, timing of O&M expenses, and lower interest expense, partially offset by higher depreciation expense.

NSP-Wisconsin — Earnings increased by $0.02 per share for the third quarter of 2018 and increased $0.03 per share year-to-date. The year-to-date increase was largely due to higher electric and natural gas rates and the impact of favorable weather and sales growth, partially offset by additional depreciation expense related to higher invested capital.

Xcel Energy Inc. and other — Xcel Energy Inc. and other, which primarily includes financing costs at the holding company and other smaller items, decreased by $0.04 per share for the third quarter of 2018 and decreased by $0.07 per share year-to-date. The decrease in earnings was primarily related to the impact of the TCJA as well as higher debt levels.

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 Sept. 30	Nine Months Ended Sept. 30
GAAP and ongoing diluted EPS — 2017	$ 0.97	$ 1.88
Components of change — 2018 vs. 2017		
Higher electric margins (excluding TCJA impacts) [(a)]	0.10	0.21
Higher natural gas margins (excluding TCJA impacts) [(a)]	0.03	0.10
Higher AFUDC — equity	0.01	0.05
Higher depreciation and amortization (excluding TCJA impacts) [(a)]	(0.03)	(0.06)
Higher O&M expenses	(0.07)	(0.05)
Higher ETR (excluding TCJA impacts) [(a)]	(0.03)	(0.04)
Higher interest charges	(0.01)	(0.03)
Other (net)	(0.01)	(0.01)
GAAP and ongoing diluted EPS — 2018	$ 0.96	$ 2.05

[(a)] Estimated net impact of the TCJA, which includes assumptions regarding future outcome of pending regulatory proceedings:		
Income tax — rate change and ARAM (net of deferral)	$ 0.25	$ 0.46
Electric margin reductions (net)	(0.15)	(0.31)
Natural gas margin reductions (net)	(0.01)	(0.03)
Depreciation and amortization reductions (Colorado prepaid pension)	(0.07)	(0.07)
Holding company — interest expense	(0.01)	(0.04)
Total	$ 0.01	$ 0.01

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. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Table of Contents

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
HDD	(18.2)%	(16.5)%	(5.6)%	(0.3)%	(13.6)%	14.2%
CDD	14.8	5.3	2.4	27.1	5.9	21.4
THI	18.2	(11.6)	35.7	38.4	(10.6)	57.0

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017	2018 vs. Normal	2017 vs. Normal	2018 vs. 2017
Retail electric	$0.043	$(0.011)	$0.054	$0.110	$(0.032)	$0.142
Firm natural gas	—	—	—	0.003	(0.020)	0.023
Total (before adjustments for decoupling)	$0.043	$(0.011)	$0.054	$0.113	$(0.052)	$0.165
Decoupling – Minnesota	(0.018)	0.015	(0.033)	(0.050)	0.023	(0.073)
Total (adjusted for decoupling)	$0.025	$0.004	$0.021	$0.063	$(0.029)	$0.092

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 Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	3.8 %	8.2 %	5.4 %	8.4 %	6.1 %
Electric commercial and industrial	1.6	2.0	6.2	4.9	3.1
Total retail electric sales	2.3	3.8	6.0	5.8	3.9
Firm natural gas sales	(1.5)	0.6	N/A	(0.3)	(0.8)

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	3.9%	(0.2)%	(0.2)%	2.0 %	1.5 %
Electric commercial and industrial	1.4	(0.3)	4.8	3.4	1.7
Total retail electric sales	2.2	(0.3)	3.8	3.0	1.6
Firm natural gas sales	1.3	(1.3)	N/A	(1.8)	0.3

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	3.1%	7.8 %	8.2 %	7.5 %	6.0 %
Electric commercial and industrial	1.3	1.9	5.6	4.2	2.8

Total retail electric sales	1.9	3.6	6.1	5.1	3.7
Firm natural gas sales	7.2	17.3	N/A	17.0	11.0

Table of Contents

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	1.5%	(0.4)%	0.8%	(0.1)%	0.5%
Electric commercial and industrial	1.0	(0.1)	4.6	3.0	1.6
Total retail electric sales	1.1	(0.2)	3.9	2.1	1.3
Firm natural gas sales	2.2	1.0	N/A	2.7	1.9

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

- PSCo’s higher residential sales growth reflects strong customer additions. Commercial and industrial (C&I) growth was due to both an increase in customers and higher average use per customer for small and large C&I customers predominately from the fabricated metal, food products and metal mining industries.
- NSP-Minnesota’s residential sales decrease was a result of lower use per customer, partially offset by customer growth. The slight decline in C&I sales was a result of an increase in customers offset by lower use per customer.
- 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 slight residential sales decline was primarily attributable to lower use per customer partially offset by customer additions. C&I growth was largely due to higher use per large customer, customer additions and increased sales to small and large sand mining customers and large customers in the energy industries.

Weather-normalized Natural Gas Sales Growth — Year-To-Date

- 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. In addition, electric customers receive a credit for PTCs that are generated in a particular period. The following table details the electric revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2018	2017	2018	2017
Electric revenues before impact of the TCJA	$2,909	$2,784	$7,665	$7,421
Electric fuel and purchased power before impact of the TCJA	(1,044)	(1,006)	(2,917)	(2,850)
Electric margin before impact of the TCJA	$1,865	$1,778	$4,748	$4,571
Impact of the TCJA (offset as a reduction in income tax expense)	(103)	—	(236)	—
Electric margin	$1,762	$1,778	$4,512	4,571

Table of Contents

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

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2018 vs. 2017	Nine Months Ended Sept. 30, 2018 vs. 2017
Trading	$ 23	$ 69
Estimated impact of weather (net of Minnesota decoupling)	18	57
Transmission revenue	16	46
Retail sales growth (including Minnesota decoupling and sales true-up)	21	35
Retail rate increase (Wisconsin, Texas and Michigan)	8	17
Non-fuel riders	3	13
Fuel and purchased power cost recovery	23	—
Other (net)	13	7
Total increase in electric revenues before impact of the TCJA	$ 125	$ 244
Impact of the TCJA (offset as a reduction in income tax expense)	(107)	(246)
Total increase (decrease) in electric revenues	$ 18	$ (2)

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2018 vs. 2017	Nine Months Ended Sept. 30, 2018 vs. 2017
Estimated impact of weather (net of Minnesota decoupling)	$ 18	$ 57
Retail sales growth (including Minnesota decoupling and sales true-up)	21	35
Purchased capacity costs	11	34
Wholesale transmission revenue (net)	13	19
Retail rate increase (Wisconsin, Texas and Michigan)	8	17
Non-fuel riders	3	13
Wisconsin fuel recovery	6	1
Other (net)	7	1
Total increase in electric margin before impact of the TCJA	$ 87	$ 177
Impact of the TCJA (offset as a reduction in income tax expense)	(103)	(236)
Total decrease in electric margin	$ (16)	$ (59)

Natural Gas Revenues and Margin

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2018	2017	2018	2017
Natural gas revenues before impact of the TCJA	$233	$214	$1,207	$1,130
Cost of natural gas sold and transported	(58)	(64)	(537)	(543)
Natural gas margin before impact of the TCJA	$175	$150	$670	$587
Impact of the TCJA (offset as a reduction in income tax expense)	(6)	—	(26)	—
Natural gas margin	$169	$150	$644	$587

Table of Contents

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2018 vs. 2017	Nine Months Ended Sept. 30, 2018 vs. 2017
Retail rate increase (Colorado, Wisconsin and Michigan)	$ 17	$ 41
Estimated impact of weather	—	18
Infrastructure and integrity riders	6	14
Conservation revenue (offset by expenses)	—	3
Sales growth	—	3
Purchased natural gas adjustment clause recovery	(5)	(5)
Other (net)	1	3
Total increase in natural gas revenues before impact of the TCJA	$ 19	$ 77
Impact of the TCJA (offset as a reduction in income tax expense)	(6)	(26)
Total increase in natural gas revenues	$ 13	$ 51

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2018 vs. 2017	Nine Months Ended Sept. 30, 2018 vs. 2017
Retail rate increase (Colorado, Wisconsin and Michigan)	$ 17	$ 41
Estimated impact of weather	—	18
Infrastructure and integrity riders	6	14
Sales growth	—	3
Conservation revenue (offset by expenses)	—	3
Other (net)	2	4
Total increase in natural gas margin before impact of the TCJA	$ 25	$ 83
Impact of the TCJA (offset as a reduction in income tax expense)	(6)	(26)
Total increase in natural gas margin	$ 19	$ 57

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $57 million, or 10.6 percent, for the third quarter of 2018 and increased $41 million, or 2.4 percent, year-to-date. The significant changes are summarized in the table below:

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

	2018 vs. 2017	2018 vs. 2017
Business systems and contract labor	$ 18	$ 33
Distribution costs	13	13
Natural gas systems damage prevention and other remediation	12	8
Plant generation costs	4	2
Nuclear plant operations and amortization	—	(16)
Other (net)	10	1
Total increase in O&M expenses	$ 57	$ 41

- Business systems and contract labor costs increased due to growing network and storage needs, cybersecurity initiatives, to support our customer strategy, and various projects and initiatives to improve business processes;
- Distribution costs reflect high maintenance expenses, including vegetation management; and
- Nuclear plant operations and amortization expenses are lower largely reflecting expense timing, savings initiatives and reduced refueling outage costs.

Table of Contents

Conservation and DSM Expenses — Conservation and DSM expenses increased $3 million, or 4.1 percent, for the third quarter of 2018 and increased $10 million, or 4.9 percent, year-to-date. The year-to-date increase was primarily due to increases in conservation programs to help customers reduce energy use. Conservation and DSM expenses are generally recovered 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 $69 million, or 18.6 percent, for the third quarter of 2018 and increased $97 million, or 8.8 percent, year-to-date. The increase was primarily driven by capital expenditures due to planned system investments and additional amortization of a prepaid pension asset in Colorado related to the electric TCJA settlement, which is offset by lower income taxes (approximately $46 million year-to-date).

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $1 million, or 0.7 percent, for the third quarter of 2018 and increased $6 million, or 1.5 percent, year-to-date. The increase was primarily due to higher property taxes in Colorado.

AFUDC, Equity and Debt — AFUDC increased $8 million for the third quarter of 2018 and $35 million year-to-date. The increase was primarily due to the Rush Creek and Hale wind projects and other capital investments.

Interest Charges — Interest charges increased $9 million, or 5.4 percent, for the third quarter of 2018 and increased $25 million, or 5.0 percent, year-to-date. 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 $132 million for the third 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 and lower pretax earnings, an increase in plant-related regulatory differences related to ARAM (net of deferrals) and an increase in investment tax credits. The ETR was 12.9 percent for the third quarter of 2018 compared with 29.4 percent for the same period in 2017.

Income tax expense decreased $237 million for the first nine months of 2018 compared with the same period in 2017. The decrease was primarily driven by a lower federal tax rate due to the TCJA and lower pretax earnings, an increase in plant-related regulatory differences related to ARAM (net of deferrals) and an increase in investment tax credits. The ETR was 15.2 percent for the first nine months of 2018 compared with 30.7 percent for the same period in 2017.

Public Utility Regulation

Except to the extent noted below and in Note 5 to the consolidated financial statements, 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 and in Item 2 of Xcel Energy Inc.'s Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

NSP-Minnesota

Wind Development — In 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 megawatts (MW) of new wind generation including ownership of 1,150 MW of wind generation.

Additionally, in April 2018, the MPUC approved NSP-Minnesota's petition 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. NSP-Minnesota's total capital investment for the Dakota Range is expected to be approximately $350 million.

In September 2018, NSP-Minnesota reached a settlement with the NDPSC Staff for these wind development projects. The settlement agreement is subject to NDPSC approval. A NDPSC decision is expected to be received by the end of 2018 or during the first quarter of 2019.

Table of Contents

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 Department of Commerce. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 kilovolts (KV) transmission line from near Mankato, Minnesota to Winnebago, Minnesota. The project was estimated by MISO to cost $108 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged 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 June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal to the 8th Circuit Court of Appeals in July 2018. It is uncertain when a decision will be rendered regarding this appeal.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 14 to the consolidated financial statements of Xcel Energy'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 included in Item 2 of Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018, appropriately represent, in all material respects, the current status of nuclear power operations, and are incorporated herein by reference.

NSP-Wisconsin

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse to Madison, Wis. Transmission Line — In 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a certificate of public convenience and necessity (CPCN) for a 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. NSP-Wisconsin's half of the line will be shared with three co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

In 2015, the PSCW approved a CPCN and route for the project. Construction is nearing completion and the project is expected to be placed-in-service in December 2018.

PSCo

Colorado Energy Plan (CEP) — In September 2018, the CPUC issued a written order approving PSCo's preferred CEP portfolio, which included the retirement of the two coal-fired generation units, Comanche Unit 1 (in 2022) and Comanche Unit 2 (in 2025), and the following additions:

	Total Capacity	PSCo's Ownership
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

PSCo is required to file for a CPCN for the owned wind generation, the purchase of the natural gas generation facility and the transmission investment, which is anticipated for later this year. PSCo's investment is expected to be approximately $1 billion, including investments in required transmission to support the significant increase in renewable generation in the state.

EVRAZ — In October 2018, the CPUC approved the application for an agreement with EVRAZ, a steelmaker in Colorado, to stabilize its rates for over 23 years through a specific customer contract and the development of a 240 MW, customer-sited solar facility. EVRAZ is PSCo’s largest customer and sought a long-term solution from state and local authorities in order to maintain and grow its operations in Colorado.

Boulder, Colorado Municipalization — In 2011, City of Boulder, Colorado (Boulder) voters passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Since that time, there have been various legal proceedings in multiple venues with jurisdiction over Boulder’s plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility as premature and the Colorado Court of Appeals ruled in PSCo’s favor, vacating a lower court decision. In June 2018, the Colorado Supreme Court rejected Boulder’s request to dismiss the case and remanded it to Boulder District Court where the litigation process has started.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position. The CPUC approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings. Those filings are due to be submitted in the fourth quarter of 2018. Boulder does not have authorization from the CPUC to initiate a condemnation proceeding at this time.

SPS

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 Electric Reliability Council of Texas, 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. In September 2018, the District Court affirmed the PUCT's ROFR order. SPS plans to file an appeal in the fourth quarter of 2018.

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 and Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018. In addition to the matters discussed in this section, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

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.

In October 2018, the FERC issued an order addressing the four complaint proceedings involving the NETOs base ROE, including the case in which the DC Circuit vacated and remanded Opinion No. 531. Under a new approach, the FERC intends to dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile, unless that presumption is sufficiently rebutted. The new approach establishes a composite zone of reasonableness based on equal weighting of the Discounted Cash

Flows (DCF), Capital Asset Pricing Model (CAPM), and expected earnings models.

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.

Derivatives, Risk Management and Market Risk

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

Table of Contents

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

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

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

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

At Sept. 30, 2018, the fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Millions of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 3	$ 6	$ —	$ —	$ 9
NSP-Minnesota	2	1	1	—	3	5
PSCo	2	1	—	—	—	1
		$ 5	$ 7	$ —	$ 3	$ 15

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

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

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

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2018	2017
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 16	$ 10
Contracts realized or settled during the period	(8)	(9)
Commodity trading contract additions and changes during the period	10	14
Fair value of commodity trading net contract assets outstanding at Sept. 30	$ 18	$ 15

Table of Contents

At Sept. 30, 2018, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1 million. At Sept. 30, 2017, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1 million.

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

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

(Millions of Dollars)	Three Months Ended Sept. 30	VaR Limit	Average	High	Low
2018	$ 0.19	$ 3.00	$ 0.20	$ 0.50	$ 0.08
2017	0.07	3.00	0.13	0.63	0.03

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 61 percent of its 2018 and approximately 24 percent of its 2019 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 34 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material.

Separately, NSP-Minnesota had enriched nuclear fuel materials in process with Westinghouse Electric Corporation (Westinghouse). Westinghouse filed for Chapter 11 bankruptcy protection in March 2017. NSP-Minnesota owned materials in Westinghouse's inventory and had contracts in place under which Westinghouse agreed to provide certain services in the 2018 PI outage. Westinghouse also agreed to provide nuclear fuel assemblies for the 2018 PI outage under its nuclear fuel fabrication contract. Westinghouse announced on Jan. 4, 2018 it agreed to be acquired by Brookfield Business Partners LP (Brookfield) and other institutional partners. Brookfield's acquisition of Westinghouse closed on Aug. 1, 2018. In connection with the acquisition, Brookfield assumed Westinghouse's contracts with NSP-Minnesota. Based on Brookfield's assumption of Westinghouse's contracts, NSP-Minnesota does not expect Westinghouse's bankruptcy or its assignment of NSP-Minnesota's contracts to Brookfield to materially impact NSP-Minnesota's operational or financial performance.

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

At Sept. 30, 2018 and 2017, a 100-basis-point change in the benchmark rate on Xcel Energy’s variable rate debt would impact pretax interest expense annually by approximately $5 million and $6 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries’ interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Sept. 30, 2018, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota’s regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

Table of Contents

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

At Sept. 30, 2018, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $33 million, while a decrease in prices of 10 percent would have resulted in a decrease in credit exposure of $8 million. At Sept. 30, 2017, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $18 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2 million.

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

Fair Value Measurements

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

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 2018. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as other comprehensive income or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2018.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 2.1 percent and 4.8 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2018.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited transparency in the auction process, fair value measurements for FTRs have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $44 million and $1 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2018.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were $5 million in Level 3 commodity derivative assets and $2 million of liabilities for options held at Sept. 30, 2018. There were $2 million of Level 3 derivative assets held as forwards at Sept. 30, 2018.

Table of Contents

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	Nine Months Ended Sept. 30 2018	2017
Cash provided by operating activities	$2,493	$2,367

Net cash provided by operating activities increased $126 million for the nine months ended Sept. 30, 2018 compared with the nine months ended Sept. 30, 2017. The increase was primarily due to the timing of recovery of certain electric and natural gas riders and vendor payments, partially offset by net income, excluding amounts related to non-cash operating activities (e.g., depreciation and deferred tax expense) and the timing of customer refunds.

(Millions of Dollars)	Nine Months Ended Sept. 30 2018	2017
Cash used in investing activities	$(2,706)	$(2,239)

Net cash used in investing activities increased $467 million for the nine months ended Sept. 30, 2018 compared with the nine months ended Sept. 30, 2017. The increase was primarily attributable to higher capital expenditures related to the Rush Creek and Hale wind generation facilities and transmission investments.

(Millions of Dollars)	Nine Months Ended Sept. 30 2018	2017
Cash provided by (used in) financing activities	$343	$(45)

Net cash provided by financing activities increased $388 million for the nine months ended Sept. 30, 2018 compared with the nine months ended Sept. 30, 2017. The increase was primarily attributable to the issuances of common stock and lower repayments of previously existing long-term debt to fund capital investment, partially offset by higher net repayments of short-term borrowings.

Capital Requirements

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

Regulation of Derivatives — In 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. The Commodity Futures Trading Commission ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to $3 billion at the end of 2019. In June 2018, the CFTC proposed to make the $8 billion threshold permanent. The ruling on this proposal is set to conclude prior to the end of 2019. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy's Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy currently meets its reporting requirements and transaction restrictions.

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

- In January 2018, contributions of $150 million were made across four of Xcel Energy’s pension plans;
- In 2017, contributions of $162 million were made across four of Xcel Energy’s pension plans; and
- For future years, contributions will be made as deemed appropriate based on evaluation of various factors including the funded status of the plans, minimum funding requirements, interest rates and expected investment returns.

Table of Contents

Capital Sources

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

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Sept. 30, 2018, approximately $152 million of cash was held in these accounts.

Credit Facilities — NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. each have five-year credit agreements with a syndicate of banks. The total size of the five-year credit facilities is $2.75 billion, and each credit facility terminates in June 2021. NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving credit facility termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

In addition, Xcel Energy Inc. entered into a $500 million 364-day term loan in December 2017. As of Sept. 30, 2018, $250 million of borrowings remain outstanding with no additional borrowing capacity.

As of Oct. 22, 2018, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility (a)	Drawn (b)	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 353	$ 897	$ 1	$ 898
PSCo	700	42	658	1	659
NSP-Minnesota	500	122	378	1	379
SPS	400	92	308	1	309
NSP-Wisconsin	150	9	141	1	142
Total	$ 3,000	$ 618	$ 2,382	$ 5	$ 2,387

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

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

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

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

In addition, Xcel Energy Inc. entered into a $500 million 364-day term loan in December 2017. As of Sept. 30, 2018, $250 million remains with no additional borrowing capacity.

Short-term debt outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$3,000	$3,250
Amount outstanding at period end	437	814
Average amount outstanding	634	644
Maximum amount outstanding	824	1,247
Weighted average interest rate, computed on a daily basis	2.45 %	1.35 %
Weighted average interest rate at period end	2.57	1.90

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates;

Table of Contents

however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

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

Capital Expenditures — The estimated base capital expenditures for Xcel Energy for 2019 through 2023 are shown in the table below:

	Base Capital Forecast					
By Subsidiary (Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
NSP-Minnesota	$2,040	$1,290	$1,540	$1,300	$1,380	$7,550
PSCo	1,020	1,730	1,335	1,395	1,530	7,010
SPS	1,130	770	460	530	635	3,525
NSP-Wisconsin	240	240	300	305	275	1,360
Other [(a)]	(50)	(70)	(25)	10	15	(120)
Total capital expenditures	$4,380	$3,960	$3,610	$3,540	$3,835	$19,325

	Base Capital Forecast					
By Function (Millions of Dollars)	2019	2020	2021	2022	2023	2019 - 2023 Total
Electric distribution	$775	$865	$1,150	$1,245	$1,270	$5,305
Electric transmission	580	560	950	870	1,055	4,015
Renewables	1,830	1,455	240	—	—	3,525
Natural gas	430	415	420	510	595	2,370
Electric generation	420	310	480	560	545	2,315
Other	345	355	370	355	370	1,795
Total capital expenditures	$4,380	$3,960	$3,610	$3,540	$3,835	$19,325

[(a)] Other category includes intercompany transfers for safe harbor wind turbines.

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

Financing for Capital Expenditures through 2023 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. The current estimated financing plans of Xcel Energy for 2019 through 2023 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$12,840
New Debt**	5,795
Equity through the Dividend Reinvestment Program (DRIP) and Benefit Program	390
Equity through the Common Equity Issuance Program	$300
Base Capital Expenditures 2019-2023	$19,325

Maturing Debt	$3,645

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

Table of Contents

2018 Financing Activity — During 2018, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing the following:

- PSCo issued $350 million of 3.70 percent first mortgage green bonds due June 15, 2028 and $350 million of 4.10 percent first mortgage green bonds due June 15, 2048;
- Xcel Energy Inc. issued $500 million of 4.00 percent senior notes due June 15, 2028 and plans to refinance the existing $500 million term loan;
- NSP-Wisconsin issued $200 million of 4.20 percent first mortgage bonds due Sept. 1, 2048; and
- SPS plans to issue up to $300 million of first mortgage bonds.

In September 2018, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $300 million of its common stock through an at-the-market offering (ATM) program in addition to $75 million of equity to be issued through the dividend reinvestment program and benefit programs. As of Sept. 30, 2018, Xcel Energy Inc. had settled 4.2 million shares of common stock with net proceeds of $199.3 million, through the ATM program. In addition, transaction fees of $1.7 million were paid. In October 2018, an additional 0.5 million shares were settled with net proceeds of $25.5 million and transaction fees of $0.2 million.

2019 Planned Financing Activity — During 2019, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $600 million of senior notes and approximately $75 million of equity through the DRIP and benefit programs;
- NSP-Minnesota plans to issue up to $700 million of first mortgage bonds;
- PSCo plans to issue approximately $600 million of first mortgage bonds;
- SPS plans to issue approximately $300 million of first mortgage bonds; and
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds.

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

Off-Balance-Sheet Arrangements

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

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

Xcel Energy 2018 Earnings Guidance — Xcel Energy narrowed its 2018 GAAP and ongoing earnings guidance range to $2.45 to $2.49 per share compared with the previous guidance range of $2.41 to $2.51 per share. Xcel Energy's original 2018 earnings guidance range was $2.37 to $2.47 per share.[a] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the remainder of the year.
- Weather-normalized retail electric sales are projected to increase approximately 1.0 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to increase 1.0 percent to 1.5 percent over 2017 levels.
- Capital rider revenue is projected to increase $35 million to $45 million (net of PTCs) over 2017 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.

- O&M expenses are projected to increase 2 percent to 3 percent over 2017 levels.
- Depreciation expense is projected to increase approximately $150 million to $160 million over 2017 levels. The change reflects an increase of $59 million for the amortization of a prepaid pension asset at PSCo, which is tax reform related and will not impact earnings.
- Property taxes are projected to increase approximately $10 million to $20 million over 2017 levels.
- Interest expense (net of AFUDC - debt) is projected to increase $25 million to $35 million over 2017 levels.
- AFUDC - equity is projected to increase approximately $20 million to $30 million from 2017 levels.
- The ETR is projected to be approximately 12 percent to 14 percent. This range may decrease to 8 percent to 10 percent as we receive clarity and direction from our commissions as to the treatment of excess deferred taxes that resulted from the TCJA. A reduction to the ETR resulting from the flowback of excess deferred taxes would be offset by a correlated reduction to revenue. Additionally, the lower ETR for 2018 compared to 2017 reflects additional PTCs which are flowed back to customers through margin.

Table of Contents

Xcel Energy 2019 Earnings Guidance — Xcel Energy's 2019 GAAP and ongoing earnings guidance is a range of $2.55 to $2.65 per share.[(a)] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns for the year.
- Weather-normalized retail electric sales are projected to be relatively flat compared with 2018 levels.
- Weather-normalized retail from natural gas sales are projected to be within a range of 0.0 percent to 1.0 percent over 2018 levels.
- Capital rider revenue is projected to increase $115 million to $125 million (net of PTCs) over 2018 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- Purchase capacity costs are expected to decline $25 million to $30 million compared with 2018 levels.
- O&M expenses are projected to be flat compared with 2017 levels.
- Depreciation expense is projected to increase approximately $120 million to $130 million over 2018 levels. Depreciation expense includes $34 million for the amortization of a prepaid pension asset at PSCo, which is tax reform related and will not impact earnings.
- Property taxes are projected to increase approximately $15 million to $25 million over 2018 levels.
- Interest expense (net of AFUDC - debt) is projected to increase $70 million to $80 million over 2018 levels.
- AFUDC - equity is projected to decrease approximately $20 million to $30 million from 2018 levels.
- The ETR is projected to be approximately 6 percent to 8 percent. The ETR reflects benefits of PTCs which are flowed back to customers through electric margin.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5 to 7 percent off of a 2018 base of $2.43 per share, which represents the mid-point of the original 2018 guidance range of $2.37 to $2.47 per share;
- Deliver annual dividend increases of 5 to 7 percent;
- Target a dividend payout ratio of 60 to 70 percent; and
- Maintain senior secured debt credit ratings in the A range.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Sept. 30, 2018, based on an evaluation carried out under the supervision and with the participation of Xcel Energy’s management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy’s disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

Table of Contents

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

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

Additional Information

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

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2017, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 2018:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2018 — July 31, 2018	—	$ —	—	—
Aug. 1, 2018 — Aug. 31, 2018	—	—	—	—
Sept. 1, 2018 — Sept. 30, 2018	—	—	—	—
Total	—		—	—

Table of Contents

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 18, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Bylaws of Xcel Energy Inc., as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K filed Feb. 18, 2016 (file no. 001-03034)).
4.01*	Supplemental Indenture dated as of Sept. 1, 2018 between Northern States Power Company and U.S. Bank National Association, as successor Trustee, creating 4.20 percent First Mortgage Bonds, Series due Sept. 1, 2048 (Exhibit 4.01 to Form 8-K of NSP-Wisconsin filed Sept. 12, 2018 (file no. 001-03140)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2018 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

Table of Contents

SIGNATURES

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

XCEL ENERGY INC.

Oct. 26, 2018 By:/s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

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