414 Nicollet Mall
Minneapolis, MN 55401

Oct. 25, 2018

XCEL ENERGY
THIRD QUARTER 2018 EARNINGS REPORT

- Xcel Energy reports 2018 third quarter EPS of $0.96 per share compared with $0.97 per share in 2017.
- Xcel Energy narrows its 2018 EPS guidance range to $2.45 to $2.49 from previous EPS guidance of $2.41 to $2.51.
- Xcel Energy initiates 2019 EPS guidance of $2.55 to $2.65.
- Xcel Energy increases its long-term EPS growth objective to 5 to 7 percent.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2018 third quarter GAAP and ongoing earnings of $491 million, or $0.96 per share, compared with $492 million, or $0.97 per share in the same period in 2017.

Earnings results for the quarter are a function of higher electric and natural gas margins due to favorable weather and sales growth, higher AFUDC and a lower tax rate, which were more than offset by higher depreciation, operating and maintenance, and interest expenses.

“Third quarter results were in line with our forecast, while our year-to-date results continue to be favorable,” said Ben Fowke, chairman, president and CEO of Xcel Energy. “We are on track to achieve our revised year-end earnings guidance, we are well positioned for the future, and we are increasing our long-term growth objective to 5 to 7 percent,”

“We reached important milestones in our strategy of expanding our clean energy portfolio and upgrading the grid, including approval of the Colorado Energy Plan and our innovative supply agreement with EVRAZ, a major Colorado employer,” said Fowke. “We also made strides in delivering new energy options and enhanced services for our customers, like our Minnesota proposal to advance the electric vehicle transition through affordable charging options and filing for approval of our RenewableConnect product in Wisconsin. These initiatives further our vision of being the preferred and trusted provider of the energy our customers need.”

At 9:00 a.m. CDT today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial-in 5 to 10 minutes prior to the start and follow the operator’s instructions.

US Dial-In:	(800) 949-2175
International Dial-In:	(323) 994-2131
Conference ID:	3269787

The conference call also will be simultaneously broadcast and archived on Xcel Energy’s website at www.xcelenergy.com. To access the presentation, click on Investor Relations. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CDT on Oct. 25 through 12:00 p.m. CDT on Oct. 28.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	3269787

Except for the historical statements contained in this release, 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 (EPS) guidance, the Tax Cut and Jobs Act (TCJA)'s impact to Xcel Energy and its customers, rate base, valuation of deferred tax assets and liabilities, cash flow, credit metrics, long-term earnings per share and dividend growth rate and potential regulatory options, as well as assumptions and other statements identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" 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 in 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.

For more information, contact:

Paul Johnson, Vice President, Investor Relations	(612) 215-4535
Olga Guteneva, Director of Investor Relations	(612) 215-4559
For news media inquiries only, please call Xcel Energy Media Relations	(612) 215-5300

Xcel Energy internet address: www.xcelenergy.com

This information is not given in connection with any sale, offer for sale or offer to buy any security.

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

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (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, operating and maintenance (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.

Note 1. Earnings Per Share Summary

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**
Public Service Company of Colorado (PSCo)	$ 0.41	$ 0.37	$ 0.91	$ 0.78
NSP-Minnesota	0.39	0.45	0.79	0.81
Southwestern Public Service Company (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.

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

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 allowance for funds used during construction (AFUDC) primarily related to the Rush Creek wind project. These items were partially offset by higher operating and maintenance (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.

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

Note 2. Regulated Utility Results

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.

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

	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 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

The following table summarizes the components of the changes in 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 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

The following table summarizes the components of the changes in 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

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, 2018 vs. 2017	Nine Months Ended Sept. 30, 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.

Conservation and DSM Expenses — Conservation and demand side management (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[a] (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.

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 vs 2017	2018	2017	2018 vs 2017
Federal statutory rate	21.0%	35.0%	(14.0)%	21.0%	35.0%	(14.0)%
State tax (net of federal tax effect)	5.0	4.1	0.9	5.0	4.1	0.9
Increase (decreases) in tax from:						
Wind production tax credits (PTCs) [a]	(2.6)	(4.8)	2.2	(4.3)	(4.5)	0.2
Regulatory differences - ARAM [b]	(5.6)	(0.1)	(5.5)	(5.6)	(0.1)	(5.5)
Regulatory differences - ARAM deferral [c]	3.8	—	3.8	4.4	—	4.4
Regulatory differences - reversal of prior quarters' ARAM deferral [c]	(7.0)	—	(7.0)	(3.3)	—	(3.3)
Regulatory differences - other utility plant items	(0.6)	(0.8)	0.2	(0.7)	(0.7)	—
Other (net)	(1.1)	(4.0)	2.9	(1.3)	(3.1)	1.8
Effective income tax rate	12.9%	29.4%	(16.5)%	15.2%	30.7%	(15.5)%

[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.

Note 3. Xcel Energy Capital Structure, Financing and Credit Ratings

Following is the capital structure of Xcel Energy:

(Millions of Dollars)	Sept. 30, 2018	Percentage of Total Capitalization	Dec. 31, 2017	Percentage of Total Capitalization
Current portion of long-term debt	$ 556	2%	$ 457	2%
Short-term debt	437	2	814	3
Long-term debt	15,508	54	14,520	53
Total debt	16,501	58	15,791	58
Common equity	12,165	42	11,455	42
Total capitalization	$ 28,666	100%	$ 27,246	100%

Credit Facilities — 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.

Credit Ratings — Access to the capital markets at reasonable terms is partially dependent on credit ratings. The following ratings reflect the views of Moody's Investors Service (Moody's), Standard & Poor's Rating Services (Standard & Poor's), and Fitch Ratings (Fitch).

The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

In October 2018, Moody's changed the outlook for Xcel Energy Inc. from stable to negative. As of Oct. 22, 2018, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

Credit Type	Company	Moody's	Standard & Poor's	Fitch
Senior Unsecured Debt	Xcel Energy Inc.	A3	BBB+	BBB+
	NSP-Minnesota	A2	A-	A
	NSP-Wisconsin	A2	A-	A
	PSCo	A3	A-	A
	SPS	Baa2	A-	BBB+
Senior Secured Debt	NSP-Minnesota	Aa3	A	A+
	NSP-Wisconsin	Aa3	A	A+
	PSCo	A1	A	A+
	SPS	A3	A	A-
Commercial Paper	Xcel Energy Inc.	P-2	A-2	F2
	NSP-Minnesota	P-1	A-2	F2
	NSP-Wisconsin	P-1	A-2	F2
	PSCo	P-2	A-2	F2
	SPS	P-2	A-2	F2

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.

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.

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.

Note 4. Rates and Regulation

PSCo - Pipeline System Integrity Adjustment (PSIA) Rider — In October 2018, PSCo, Colorado Public Utilities Commission (CPUC) Staff, and the Office of Consumer Counsel (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.

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 certificate of public convenience and necessity 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.

PSCo – 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.

SPS – 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 Public Utility Commission of Texas (PUCT). The request was based on a historic test year (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 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.

SPS – New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the New Mexico Public Regulation Commission (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 New Mexico Supreme Court (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.

Note 5. Tax Cuts and Jobs Act

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.

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. A commission decision is pending.

NSP-Wisconsin — In May 2018, the Public Service Commission of Wisconsin 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 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 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 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.

Note 6. Xcel Energy 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.

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.

XCEL ENERGY INC. AND SUBSIDIARIES
EARNINGS RELEASE SUMMARY (UNAUDITED)
(amounts in millions, except per share data)

	Three Months Ended Sept. 30	
	2018	2017
Operating revenues:		
Electric and natural gas	$ 3,029	$ 2,998
Other	19	19
Total operating revenues	3,048	3,017
Net income	$ 491	$ 492
Weighted average diluted common shares outstanding	511	509
Components of EPS — Diluted		
Regulated utility	$ 1.03	$ 1.00
Xcel Energy Inc. and other costs	(0.07)	(0.03)
GAAP and ongoing diluted EPS	**$ 0.96**	**$ 0.97**

	Nine Months Ended Sept. 30	
	2018	2017
Operating revenues:		
Electric and natural gas	$ 8,600	$ 8,551
Other	57	58
Total operating revenues	8,657	8,609
Net income	$ 1,047	$ 959
Weighted average diluted common shares outstanding	510	509
Components of EPS — Diluted		
Regulated utility	$ 2.22	$ 1.98
Xcel Energy Inc. and other costs	(0.17)	(0.10)
GAAP and ongoing diluted EPS	**2.05**	**1.88**
Book value per share	$ 23.85	$ 22.53