April 26, 2018

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
FIRST QUARTER 2018 EARNINGS REPORT

- GAAP and ongoing 2018 first quarter earnings per share were $0.57 compared with $0.47 per share in 2017.
- Xcel Energy reaffirms 2018 GAAP and ongoing earnings guidance of $2.37 to $2.47 per share.

MINNEAPOLIS — Xcel Energy Inc. (NASDAQ: XEL) today reported 2018 first quarter GAAP and ongoing earnings of $291 million, or $0.57 per share, compared with $239 million, or $0.47 per share in the same period in 2017.

GAAP and ongoing earnings were higher as a result of increased electric and natural gas margins (excluding the impact of the Tax Cuts and Jobs Act) which reflect favorable weather compared to last year, timing of operating and maintenance expenses and an increased allowance for funds used during construction, partially offset by higher depreciation and interest expenses.

"Xcel Energy delivered solid first-quarter results and is well-positioned to achieve our overall objectives for 2018," said Ben Fowke, chairman, president and CEO of Xcel Energy. "We are happy with our progress in executing our industry-leading wind energy expansion that puts us on pace to achieve over a 60 percent reduction in carbon across our eight states by 2030 while keeping customer bills affordable and helping our stakeholders achieve their policy goals."

"We combined our financial performance with outstanding operational performance. In April, two of our states weathered epic storms; a historic blizzard buried Minnesota with record snow totals and days later, a fierce wind storm battered Colorado with hurricane-force gusts. Our crews worked around the clock, facing challenging conditions to get the lights back on for thousands of our customers and communities, and demonstrated why I believe we have the best storm response in the industry," concluded Fowke.

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) 967-7137
International Dial-In:	(719) 457-2735
Conference ID:	3737478

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 1:00 p.m. CDT on April 26 through 11:00 p.m. CDT on April 29.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	3737478

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: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) to obtain financing on favorable terms; business conditions in the energy industry; including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by Xcel Energy; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

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 March 31	
	2018	2017
Operating revenues		
Electric	$ 2,270	$ 2,299
Natural gas	662	626
Other	19	21
Total operating revenues	2,951	2,946
Operating expenses		
Electric fuel and purchased power	932	925
Cost of natural gas sold and transported	375	365
Cost of sales — other	8	9
Operating and maintenance expenses	557	580
Conservation and demand side management expenses	71	68
Depreciation and amortization	383	365
Taxes (other than income taxes)	145	142
Total operating expenses	2,471	2,454
Operating income	480	492
Other income, net	1	1
Equity earnings of unconsolidated subsidiaries	6	8
Allowance for funds used during construction — equity	23	14
Interest charges and financing costs		
Interest charges — includes other financing costs of $6 and $6, respectively	171	166
Allowance for funds used during construction — debt	(11)	(7)
Total interest charges and financing costs	160	159
Income before income taxes	350	356
Income taxes	59	117
Net income	$ 291	$ 239
Weighted average common shares outstanding:		
Basic	509	508
Diluted	509	509
Earnings per average common share:		
Basic	$ 0.57	$ 0.47
Diluted	0.57	0.47
Cash dividends declared per common share	$ 0.38	$ 0.36

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 months ended March 31, 2017 and 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Note 1. Earnings Per Share Summary

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

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

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

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

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

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

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

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

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
GAAP and ongoing diluted EPS — 2017	**$ 0.47**
Components of change — 2018 vs. 2017	
Higher electric margins (excluding TCJA impacts) [(a)]	0.04
Higher natural gas margins (excluding TCJA impacts) [(a)]	0.04
Lower O&M expenses	0.03
Higher AFUDC — equity	0.02
Lower ETR (excluding TCJA impacts) [(a) (b)]	0.01
Higher depreciation and amortization	(0.02)
Higher interest charges	(0.01)
Other, net	(0.01)
GAAP and ongoing diluted EPS — 2018	**$ 0.57**

[(a)] TCJA impact:

Income tax - rate change	$ 0.10
Electric revenue reductions	(0.08)
Gas revenue reductions	(0.01)
Holding company - interest expense	(0.01)
Total	$ —

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

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.

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

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

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

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

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

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

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

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

Weather-normalized Electric Sales Growth (Decline)

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

Weather-normalized Natural Gas Sales Growth

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

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

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

The following table summarizes the components of the changes in electric margin:

(Millions of Dollars)	**Three Months Ended March 31, 2018 vs. 2017**
Firm wholesale	$ (7)
Estimated impact of weather, net of Minnesota decoupling	15
Purchased capacity costs	11
Retail rate increase (Wisconsin)	5
Other, net	3
Total increase in electric margin before impact of the TCJA	$ 27
Impact of the TCJA (offset as a reduction in income tax expense)	(63)
Total decrease in electric margin	$ (36)

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

The following table summarizes the components of the changes in natural gas margin:

(Millions of Dollars)	Three Months Ended March 31, 2018 vs. 2017	
Estimated impact of weather	$	15
Retail rate increase (Colorado - interim, subject to refund, Wisconsin and Michigan)		12
Infrastructure and integrity riders		4
Sales growth		2
Other, net		4
Total increase in natural gas margin before impact of the TCJA	$	37
Impact of the TCJA (offset as a reduction in income tax expense)		(11)
Total increase in natural gas margin	$	26

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

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

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

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

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

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

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

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

Income Taxes — Income tax expense decreased $58 million for the first quarter of 2018 compared with the same period in 2017. The decrease was primarily driven by a lower federal tax rate due to the TCJA, an increase in wind PTCs, an increase in plant-related regulatory differences related to ARAM [(a)] and an increase in other tax credits. This was partially offset by the deferral of ARAM. The following table reconciles the effective tax rate for the first quarter of 2018 and 2017.

	Three Months ended March 31		
	2018	2017	2018 vs 2017
Federal statutory rate	21.0%	35.0%	(14.0)%
State tax, net of federal tax effect	4.9%	4.0%	0.9 %
Increases (decreases) in tax from:			
Wind production tax credits	(6.0)	(4.0)	(2.0)
Regulatory differences - ARAM	(5.8)	(0.1)	(5.7)
Regulatory differences - ARAM deferral [(b)]	5.4	—	5.4
Regulatory differences - other utility plant items	(1.0)	(0.5)	(0.5)
Other, net	(1.6)	(1.5)	(0.1)
Effective income tax rate	16.9%	32.9%	(16.0)%

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

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

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

Following is the capital structure of Xcel Energy:

(Millions of Dollars)	March 31, 2018	Percentage of Total Capitalization	Dec. 31, 2017	Percentage of Total Capitalization
Current portion of long-term debt	$ 457	1%	$ 457	2%
Short-term debt	1,025	4	814	3
Long-term debt	14,522	53	14,520	53
Total debt	16,004	58	15,791	58
Common equity	11,561	42	11,455	42
Total capitalization	$ 27,565	100%	$ 27,246	100%

Credit Facilities — As of April 23, 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.	$ 1,500	$ 775	$ 725	$ 1	$ 726
PSCo	700	54	646	1	647
NSP-Minnesota	500	36	464	1	465
SPS	400	19	381	1	382
NSP-Wisconsin	150	36	114	—	114
Total	$ 3,250	$ 920	$ 2,330	$ 4	$ 2,334

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

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

Credit Ratings — Access to the capital market 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.

As of April 23, 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	Baa1	A-	BBB+
Senior Secured Debt	NSP-Minnesota	Aa3	A	A+
	NSP-Wisconsin	Aa3	A	A+
	PSCo	A1	A	A+
	SPS	A2	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

Financing Activity — Xcel Energy Inc. and its utility subsidiaries' 2018 financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $750 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $300 million of first mortgage bonds;
- NSP-Wisconsin plans to issue approximately $200 million of first mortgage bonds;
- PSCo plans to issue approximately $750 million of first mortgage bonds; and
- SPS plans to issue approximately $350 million of first mortgage bonds.

Xcel Energy also plans to issue approximately $300 million of incremental equity in 2018 in addition to approximately $75 million of equity to be issued through the dividend reinvestment program and benefit programs.

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

Note 4. Rates and Regulation

NSP-Minnesota – Dakota Range — In 2017, NSP-Minnesota filed with the Minnesota Public Utility Commission (MPUC) and the North Dakota Public Service Commission (NDPSC) seeking approval to build and own the Dakota Range, a 300 MW wind project in South Dakota. The project is expected to be placed into service by the end of 2021 and qualify for 80 percent of the PTC. In March 2018, NSP-Minnesota submitted supplemental filings to the MPUC and NDPSC regarding the impacts of the TCJA and other updated information for Dakota Range. These impacts result in a minimal increase in the revenue requirement for Dakota Range and the project continues to show significant benefits to customers. MPUC and NDPSC decisions are pending.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The following table summarizes SPS' rate increase request:

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

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

Key dates in the revised procedural schedule are as follows:

- Intervenors' direct testimony — April 25, 2018;
- PUCT Staff direct testimony — May 2, 2018;
- PUCT Staff and intervenors' cross-rebuttal testimony — May 14, 2018;
- SPS' rebuttal testimony — May 23, 2018; and
- Hearings — June 4 - 14, 2018.

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

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

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

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

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

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

Key dates in the procedural schedule are as follows:

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

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

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

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

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

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

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

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. Each of the states in Xcel Energy's service areas have opened dockets to address the impacts of the TCJA. Xcel Energy has made filings and is working with various stakeholders in its jurisdictions to determine the appropriate treatment for the TCJA.

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

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

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

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

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

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

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

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

SPS — In January 2018, the PUCT issued an order requiring utilities to apply deferred accounting for the impacts of the TCJA. In February 2018, SPS filed with the PUCT supplemental testimony, which indicated that the TCJA would reduce revenue requirements by approximately $32 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending Texas electric rate case, as discussed in Note 4.

In February 2018, SPS filed with the NMPRC a preliminary quantification of the impacts of the TCJA on its ongoing New Mexico 2017 electric rate case, which indicated that the TCJA would reduce revenue requirements by approximately $11 million and recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. The impact of the TCJA is expected to be addressed as part of SPS' pending New Mexico electric rate case, as discussed in Note 4.

Note 6. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2018 Earnings Guidance — Xcel Energy's 2018 GAAP and ongoing earnings guidance is $2.37 to $2.47 per share.[(a)] Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to be within a range of 0 percent to 0.5 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent over 2017 levels.
- Capital rider revenue is projected to increase by $30 million to $40 million over 2017 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- O&M expenses are projected to be flat to 2017 levels.
- Depreciation expense is projected to increase approximately $120 million to $130 million over 2017 levels. The change is depreciation expense is largely due to the dismissal of the PSCo electric rate case, which delays the impact of higher depreciation rates.
- Property taxes are projected to increase approximately $30 million to $40 million over 2017 levels.
- Interest expense (net of AFUDC - debt) is projected to increase $30 million to $40 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 15 percent to 17 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.

(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 percent to 6 percent off of a 2017 base of $2.30 per share;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

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

	Three Months Ended March 31	
	2018	2017
Operating revenues:		
Electric and natural gas	$ 2,932	$ 2,925
Other	19	21
Total operating revenues	2,951	2,946
Net income	$ 291	$ 239
Weighted average diluted common shares outstanding	509	509
Components of EPS — Diluted		
Regulated utility	$ 0.62	$ 0.51
Xcel Energy Inc. and other costs	(0.05)	(0.04)
GAAP and ongoing diluted EPS	**$ 0.57**	**$ 0.47**
Book value per share	$ 22.73	$ 21.80