Oct. 27, 2016

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
THIRD QUARTER 2016 EARNINGS REPORT

- GAAP (generally accepted accounting principles) and ongoing 2016 third quarter earnings per share were $0.90 compared with $0.84 per share in 2015.
- Xcel Energy is narrowing its 2016 ongoing earnings guidance range to $2.17 to $2.22, compared to the previous range of $2.12 to $2.27 per share.
- Xcel Energy initiates 2017 ongoing earnings guidance of $2.25 to $2.35 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2016 third quarter GAAP and ongoing earnings of $458 million, or $0.90 per share, compared with $426 million, or $0.84 per share, in the same period in 2015.

Electric and natural gas margins rose in the third quarter primarily driven by higher retail electric and natural gas rates and non-fuel riders to recover our capital investments, along with higher sales growth. These positive factors and a lower effective tax rate were offset by higher depreciation, operating and maintenance expenses and interest charges.

“Third quarter results were in line with our plan and we are confident we will deliver earnings within our narrowed 2016 guidance range,” said Chairman, President and CEO Ben Fowke. “We continue to see new customer growth in much of our service territories, which has materialized into improved sales.”

“We are successfully executing our strategy by settling rate cases in Minnesota and Texas and achieving several milestones in our steel-for-fuel strategy with the approval of the Rush Creek wind farm in Colorado and our proposal to build and own 750 megawatts of new wind in the Upper Midwest. The abundance of wind in our service territory puts us in a unique position to continue to capitalize on this clean energy resource and drive significant carbon reductions at a tremendous value to our customers.”

“These actions provide a solid foundation for 2017 earnings guidance consistent with our long-term growth objective,” concluded Fowke.

Earnings Adjusted for Certain Items (Ongoing Earnings)

The following table provides a reconciliation of ongoing earnings per share (EPS) to GAAP EPS:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2016**	**2015**	**2016**	**2015**
Ongoing diluted EPS	$ 0.90	$ 0.84	$ 1.76	$ 1.69
Loss on Monticello life cycle management/extended power uprate project [(a)]	—	—	—	(0.16)
GAAP diluted EPS	**$ 0.90**	**$ 0.84**	**$ 1.76**	**$ 1.53**

(a) See Note 6.

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:	(888) 455-2311
International Dial-In:	(719) 325-2474
Conference ID:	5131866

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. 27 through 10:59 p.m. CDT on Oct. 30.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	5131866

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 2016 and 2017 earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" 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, 2015, Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016 and June 30, 2016, 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; availability of cost of capital; and employee work force factors.

For more information, contact:

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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 thousands, except per share data)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2016	2015	2016	2015
Operating revenues				
Electric	$ 2,799,964	$ 2,667,480	$ 7,209,225	$ 7,105,803
Natural gas	221,956	216,019	1,046,544	1,216,146
Other	18,227	17,813	56,500	56,716
Total operating revenues	3,040,147	2,901,312	8,312,269	8,378,665
Operating expenses				
Electric fuel and purchased power	1,037,263	1,014,726	2,755,083	2,869,563
Cost of natural gas sold and transported	67,566	66,071	469,754	665,109
Cost of sales — other	8,648	8,203	25,225	26,416
Operating and maintenance expenses	590,009	565,984	1,764,397	1,746,093
Conservation and demand side management program expenses	63,914	57,314	177,266	165,260
Depreciation and amortization	328,503	280,121	971,057	827,821
Taxes (other than income taxes)	117,190	123,081	400,982	389,438
Loss on Monticello life cycle management/extended power uprate project	—	—	—	129,463
Total operating expenses	2,213,093	2,115,500	6,563,764	6,819,163
Operating income	827,054	785,812	1,748,505	1,559,502
Other income, net	578	1,626	6,388	5,748
Equity earnings of unconsolidated subsidiaries	9,701	8,162	32,500	24,360
Allowance for funds used during construction — equity	17,199	15,427	45,042	40,728
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,060, $6,260, $19,026 and $17,819, respectively	165,857	152,566	485,280	441,728
Allowance for funds used during construction — debt	(7,532)	(7,031)	(20,206)	(19,340)
Total interest charges and financing costs	158,325	145,535	465,074	422,388
Income before income taxes	696,207	665,492	1,367,361	1,207,950
Income taxes	238,412	239,029	471,459	432,490
Net income	$ 457,795	$ 426,463	$ 895,902	$ 775,460
Weighted average common shares outstanding:				
Basic	508,941	508,031	508,840	507,585
Diluted	509,566	508,427	509,396	507,976
Earnings per average common share:				
Basic	$ 0.90	$ 0.84	$ 1.76	$ 1.53
Diluted	0.90	0.84	1.76	1.53
Cash dividends declared per common share	$ 0.34	$ 0.32	$ 1.02	$ 0.96

XCEL ENERGY INC. AND SUBSIDIARIES

Notes to Investor Relations Earnings Release (Unaudited)

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

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following table summarizes diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2016**	**2015**	**2016**	**2015**
Public Service Company of Colorado (PSCo)	$ 0.34	$ 0.34	$ 0.74	$ 0.75
NSP-Minnesota	0.41	0.35	0.74	0.65
Southwestern Public Service Company (SPS)	0.13	0.12	0.24	0.21
NSP-Wisconsin	0.05	0.05	0.11	0.13
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.03
Regulated utility	0.94	0.87	1.87	1.77
Xcel Energy Inc. and other	(0.04)	(0.03)	(0.11)	(0.08)
Ongoing diluted EPS	0.90	0.84	1.76	1.69
Loss on Monticello life cycle management (LCM)/extended power uprate (EPU) project [(a)]	—	—	—	(0.16)
GAAP diluted EPS	**$ 0.90**	**$ 0.84**	**$ 1.76**	**$ 1.53**

(a) See Note 6.

PSCo — PSCo's ongoing earnings were flat for the third quarter of 2016 and decreased $0.01 per share year-to-date. Year-to-date, higher natural gas margins, primarily due to rate increases, and higher allowance for funds used during construction (AFUDC) were offset by higher depreciation, operating and maintenance (O&M) expenses and interest charges.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.06 for the third quarter of 2016 and $0.09 per share year-to-date. Year-to-date, higher electric revenues driven by an interim electric rate increase in Minnesota (subject to refund) and non-fuel riders were partially offset by higher depreciation, O&M expenses, interest charges and property taxes.

SPS — SPS' ongoing earnings increased $0.01 for the third quarter of 2016 and $0.03 per share year-to-date. Year-to-date, higher electric margins and lower O&M expenses were partially offset by an increase in depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for the third quarter of 2016 and decreased $0.02 per share year-to-date. Year-to-date, the positive impact of higher electric revenues, primarily driven by an electric rate increase, was offset by higher O&M expenses and depreciation.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Ongoing earnings decreased by $0.01 for the third quarter of 2016 and $0.03 per share year-to-date, primarily related to higher long-term debt levels.

The following table summarizes significant components contributing to the changes in 2016 EPS compared with the same period in 2015:

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2015 GAAP diluted EPS	**$ 0.84**	**$ 1.53**
Loss on Monticello LCM/EPU project [a]	—	0.16
2015 ongoing diluted EPS	**0.84**	**1.69**
Components of change — 2016 vs. 2015		
Higher electric margins [b]	0.14	0.27
Lower effective tax rate (ETR)	0.02	0.04
Higher natural gas margins [c]	0.01	0.03
Higher depreciation and amortization	(0.06)	(0.17)
Higher interest charges	(0.02)	(0.05)
Higher O&M expenses	(0.03)	(0.03)
Other, net	—	(0.02)
2016 GAAP and ongoing diluted EPS	**$ 0.90**	**$ 1.76**

[a] See Note 6.
[b] Reflects $0.006 and $0.015 attributable to weather for the three and nine months ended Sept. 30, 2016, respectively.
[c] Reflects $0.001 and $(0.007) attributable to weather for the three and nine months ended Sept. 30, 2016, respectively.

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 the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

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

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		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
HDD	(52.6)%	(57.9)%	11.1%	(12.7)%	(4.2)%	(8.4)%
CDD	11.0	15.1	(3.1)	8.3	5.4	3.3
THI	6.5	4.3	3.2	8.6	(1.6)	11.2

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015	2016 vs. Normal	2015 vs. Normal	2016 vs. 2015
Retail electric	$ 0.016 [a]	$ 0.010	$ 0.006	$ 0.011 [a]	$ (0.004)	$ 0.015
Firm natural gas	(0.001)	(0.002)	0.001	(0.014)	(0.007)	(0.007)
Total	$ 0.015	$ 0.008	$ 0.007	$ (0.003)	$ (0.011)	$ 0.008

(a) Excludes $0.008 and $0.009 favorable weather impact due to electric sales decoupling at NSP-Minnesota for the three and nine months ended Sept. 30, 2016, respectively.

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2016 compared to the same period in 2015:

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	5.6%	4.7%	1.5%	2.8%	4.4%
Electric commercial and industrial	0.1	0.8	3.6	—	1.2
Total retail electric sales	2.0	2.0	3.2	0.7	2.2
Firm natural gas sales	3.5	(5.0)	N/A	(12.8)	(0.2)

	Three Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	4.8%	2.0%	1.0%	1.0%	2.8%
Electric commercial and industrial	0.5	0.2	3.4	(0.2)	1.0
Total retail electric sales	2.1	0.8	3.1	—	1.6
Firm natural gas sales	(1.6)	(4.9)	N/A	(12.9)	(3.2)

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	4.2%	1.7%	(1.7)%	(0.5)%	1.9%
Electric commercial and industrial	(0.7)	(0.3)	1.6	(0.3)	—
Total retail electric sales	0.9	0.3	1.0	(0.5)	0.6
Firm natural gas sales	3.2	(9.0)	N/A	(12.5)	(1.8)

	Nine Months Ended Sept. 30				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	3.4%	0.6%	(1.2)%	(0.3)%	1.3%
Electric commercial and industrial	(0.7)	(0.7)	1.2	(0.4)	(0.3)
Total retail electric sales	0.7	(0.3)	0.8	(0.5)	0.2
Firm natural gas sales	0.9	(0.6)	N/A	(4.7)	—

Weather-normalized - adjusted for leap day	Nine Months Ended Sept. 30 (Excluding Leap Day) [b] PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Electric residential [a]	3.0%	0.2%	(1.6)%	(0.7)%	0.9%
Electric commercial and industrial	(1.1)	(1.1)	0.8	(0.7)	(0.6)
Total retail electric sales	0.3	(0.7)	0.4	(0.8)	(0.2)
Firm natural gas sales	0.1	(1.4)	N/A	(5.4)	(0.7)

(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 30-40 basis points for retail electric and 70-80 basis points for firm natural gas for the nine months ended Sept. 30, 2016.

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

- PSCo's residential growth reflects an increased number of customers and higher use per customer. The commercial and industrial (C&I) decline was mainly due to lower sales to certain large customers that support the mining, oil and gas industries. The decline was partially offset by an increase in the number of small C&I customers.
- NSP-Minnesota's residential sales growth reflects customer additions, partially offset by lower use per customer. C&I sales declined primarily as a result of lower use by small and large customers in the manufacturing industry.
- SPS' residential sales decline was primarily the result of lower use per customer. The increase in C&I sales was driven by oil and natural gas production in the Southeastern New Mexico, Permian Basin area as well as greater use by agricultural customers.
- NSP-Wisconsin's residential sales decrease was primarily attributable to lower use per customer, partially offset by customer additions. The C&I decline was largely due to reduced sales to small customers in the sand mining industry. The overall decrease was partially offset by an increase in the number of large and small C&I customers as well as greater use per customer in the large C&I class for the oil and gas industries.

Weather-normalized Natural Gas Sales Decline — Year-To-Date (Excluding Leap Day)

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use, partially offset by a slight increase in the number of customers.

Electric Margin — Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	Three Months Ended Sept. 30 2016	2015	Nine Months Ended Sept. 30 2016	2015
Electric revenues	$ 2,800	$ 2,667	$ 7,209	$ 7,106
Electric fuel and purchased power	(1,037)	(1,015)	(2,755)	(2,870)
Electric margin	$ 1,763	$ 1,652	$ 4,454	$ 4,236

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

(Millions of Dollars)	Three Months Ended Sept. 30 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Retail rate increases [(a)]	$ 59	$ 132
Estimated impact of weather	11	19
Non-fuel riders	8	16
Retail sales growth, excluding weather impact	18	15
Transmission revenue, net of costs	1	13
Conservation incentive	7	7
Weather decoupling-Minnesota	(6)	(7)
PSCo earnings test refund	5	(1)
Other, net	8	24
Total increase in electric margin	$ 111	$ 218

(a) Increase is primarily due to interim rates in Minnesota (subject to and net of estimated provision for refund) and final rates in Wisconsin.

Natural Gas Margin — Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas has minimal impact on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2016	2015	2016	2015
Natural gas revenues	$ 222	$ 216	$ 1,047	$ 1,216
Cost of natural gas sold and transported	(68)	(66)	(470)	(665)
Natural gas margin	$ 154	$ 150	$ 577	$ 551

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

(Millions of Dollars)	Three Months Ended Sept. 30 2016 vs. 2015	Nine Months Ended Sept. 30 2016 vs. 2015
Retail rate increases [(a)]	$ 8	$ 32
Estimated impact of weather	—	(5)
Non-fuel riders	(3)	(5)
Other, net	(1)	4
Total increase in natural gas margin	$ 4	$ 26

(a) Increase is primarily related to final rates in Colorado.

O&M Expenses — O&M expenses increased $24.0 million, or 4.2 percent, for the third quarter of 2016 and $18.3 million, or 1.0 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. The year-to-date increase was mainly due to additional maintenance activities and storm related costs, which were partially offset by a reduction in the timing and scope of plant outages and discovery work.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses increased $6.6 million, or 11.5 percent, for the third quarter of 2016 and $12.0 million, or 7.3 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to more customer participation in DSM programs which has led to additional customer rebates and increased program implementation costs. Higher conservation and DSM program expenses are generally offset by higher revenues due to recovery mechanisms.

Depreciation and Amortization — Depreciation and amortization increased $48.4 million, or 17.3 percent, for the third quarter of 2016 and $143.2 million, or 17.3 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were primarily attributable to capital investments, including Pleasant Valley and Border Wind Farms, reduction of the excess depreciation reserve in Minnesota and the full amortization of the Department of Energy (DOE) settlement in 2015.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) decreased $5.9 million, or 4.8 percent, for the third quarter of 2016 and increased $11.5 million, or 3.0 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. The year-to-date increase was primarily due to higher property taxes in Minnesota, excluding the impact of the proposed settlement agreement in the Minnesota 2016 multi-year electric rate case.

Interest Charges — Interest charges increased $13.3 million, or 8.7 percent, for the third quarter of 2016 and $43.6 million, or 9.9 percent, for the nine months ended Sept. 30, 2016 compared with the same periods in 2015. Increases were related to higher long-term debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased $0.6 million for the third quarter of 2016 compared with the same period in 2015. The decrease was primarily due to increased wind production tax and research and experimentation credits in 2016, partially offset by higher pretax earnings in 2016. The effective tax rate (ETR) was 34.2 percent for the third quarter of 2016 compared with 35.9 percent for the same period in 2015. The lower ETR in 2016 is primarily due to the adjustments referenced above.

Income tax expense increased $39.0 million for the first nine months of 2016 compared with the same period in 2015. The increase in income tax expense was primarily due to higher pretax earnings, partially offset by increased wind production tax and research and experimentation credits. The ETR was 34.5 percent for the first nine months of 2016 compared with 35.8 percent for the same period in 2015. The lower ETR in 2016 is primarily due to the adjustments referenced above.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Sept. 30, 2016	Percentage of Total Capitalization	Dec. 31, 2015	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.7	3%	$ 0.7	3%
Short-term debt	0.4	2	0.8	3
Long-term debt	13.4	52	12.4	51
Total debt	14.5	57	13.9	57
Common equity	11.0	43	10.6	43
Total capitalization	$ 25.5	100%	$ 24.5	100%

Credit Facilities — As of Oct. 24, 2016, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,000	$ 263	$ 737	$ —	$ 737
PSCo	700	22	678	1	679
NSP-Minnesota	500	11	489	—	489
SPS	400	5	395	1	396
NSP-Wisconsin	150	37	113	1	114
Total	$ 2,750	$ 338	$ 2,412	$ 3	$ 2,415

(a) These credit facilities expire in June 2021.
(b) Includes outstanding commercial paper and letters of credit.

Credit Ratings — Access to the capital market at reasonable terms is dependent in part 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 Oct. 24, 2016, 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

Capital Expenditures — The current estimated base capital expenditure programs of Xcel Energy's operating companies for years 2017 through 2021 are shown in the table below:

	Capital Forecast					
(Millions of Dollars)	**2017**	**2018**	**2019**	**2020**	**2021**	**2017 - 2021 Total**
By Subsidiary						
NSP-Minnesota	$ 1,195	$ 1,170	$ 1,515	$ 1,405	$ 1,220	$ 6,505
PSCo	1,590	1,670	1,190	1,030	980	6,460
SPS	610	570	490	400	450	2,520
NSP-Wisconsin	250	280	250	280	300	1,360
Other	10	10	510	510	500	1,540
Total capital expenditures	$ 3,655	$ 3,700	$ 3,955	$ 3,625	$ 3,450	$ 18,385

	Capital Forecast					
(Millions of Dollars)	**2017**	**2018**	**2019**	**2020**	**2021**	**2017 - 2021 Total**
By Function						
Electric transmission	$ 795	$ 840	$ 750	$ 690	$ 805	$ 3,880
Electric distribution	760	865	950	905	955	4,435
Electric generation	670	685	655	405	485	2,900
Natural gas	400	415	420	420	415	2,070
Renewables	610	555	915	925	500	3,505
Other	420	340	265	280	290	1,595
Total capital expenditures	$ 3,655	$ 3,700	$ 3,955	$ 3,625	$ 3,450	$ 18,385

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, renewable portfolio standards and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy's transmission-only subsidiaries.

Financing — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. Xcel Energy does not anticipate issuing any equity to fund its capital investment program for 2017-2021. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2017 through 2021 are shown in the table below.

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from Operations*	$	13,465
New Debt**		4,920
Equity		—
2017-2021 Capital Expenditures	$	18,385
Maturing Debt	$	3,550

* Net of dividends.
** Reflects a combination of short and long-term debt.

Xcel Energy Inc. and its utility subsidiaries' 2017 financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately $300 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds;
- PSCo plans to issue approximately $400 million of first mortgage bonds; and
- SPS plans to issue approximately $150 million of first mortgage bonds.

2016 Financing Activity — During 2016, Xcel Energy Inc. and its utility subsidiaries issued and anticipate issuing the following:

- In March, Xcel Energy Inc. issued $400 million of 2.4 percent senior notes due March 15, 2021 and $350 million of 3.3 percent senior notes due June 1, 2025;
- In May, NSP-Minnesota issued $350 million of 3.6 percent first mortgage bonds due May 15, 2046;
- In June, PSCo issued $250 million of 3.55 percent first mortgage bonds due June 15, 2046;
- In August, SPS issued $300 million of 3.4 percent first mortgage bonds due Aug. 15, 2046; and
- Xcel Energy Inc. plans to issue approximately $800 million of senior notes in the fourth quarter.

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

Note 4. Rates and Regulation

Minnesota 2016 Multi-Year Electric Rate Case — In November 2015, NSP-Minnesota filed a three-year electric rate case with the Minnesota Public Utilities Commission (MPUC). The rate case is based on a requested return on equity (ROE) of 10.0 percent and a 52.50 percent equity ratio. The request is detailed in the table below:

Request (Millions of Dollars)		2016		2017		2018
Rate request	$	194.6	$	52.1	$	50.4
Increase percentage		6.4%		1.7%		1.7%
Interim request	$	163.7	$	44.9		N/A
Rate base	$	7,800	$	7,700	$	7,700

In December 2015, the MPUC approved interim rates for 2016.

Settlement Agreement

In August 2016, NSP-Minnesota reached a settlement with the Minnesota Department of Commerce (DOC), Xcel Large Industrials, the Minnesota Chamber of Commerce, the Commercial Group, the Suburban Rate Authority, the City of Minneapolis, the Industrial, Commercial, and Institutional Group, and the Energy CENTS Coalition, which resolves all revenue requirement issues in dispute. The settlement agreement requires the approval of the MPUC.

Key terms of the settlement are listed below:

- The agreement reflects a four-year period covering 2016-2019;
- The stated revenue increases in the table below are based on the DOC's sales forecast;
- Annual sales true-up to weather-normalized actuals all years, all classes:
  - 2016 weather-normalized actuals used to set final 2016 rates, no cap;
  - 2016-2019 full decoupling for decoupled classes (residential, non-demand metered commercial) with 3 percent cap; and
  - 2017-2019 annual true-up for non-decoupled classes with 3 percent cap.
- An ROE of 9.2 percent and an equity ratio of 52.5 percent;
- The nuclear related costs in this rate case will not be considered provisional;
- Continued use of all existing riders during the four-year term, however no new riders or legislative additions would be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019; and
- A four-year stay out provision for rate cases.

Compliance steps recommended by the settling parties to implement the settlement:

- A property tax true-up mechanism for 2017-2019; and
- A capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, incremental)	2016	2017	2018	2019	Total
Settlement revenues [a]	$ 74.99	$ 59.86	$ —	$ 50.12	$ 184.97
NSP-Minnesota's sales forecast [b]	37.40	—	—	—	37.40
Total rate impact	$ 112.39	$ 59.86	$ —	$ 50.12	$ 222.37

(a) The settlement revenue increase reflects an increase of 2.47 percent in 2016; 1.97 percent in 2017; 0 percent in 2018 and 1.65 percent in 2019.

(b) The table reflects the estimated rate impact of this agreement, using NSP-Minnesota's original sales forecast as filed in the Minnesota rate case. The settlement agreement includes a provision to true-up estimated sales to the actual sales for 2016.

The revised schedule for the Minnesota rate case is listed below:

- Administrative law judge report — March 3, 2017; and
- MPUC decision — June 2017.

A current liability that is consistent with the settlement and represents NSP-Minnesota's best estimate of a refund obligation for 2016 associated with interim rates was recorded as of Sept. 30, 2016.

NSP Resource Plans — In January 2015, NSP-Minnesota filed its 2016-2030 Integrated Resource Plan (the Plan) with the MPUC.

In October 2016, the MPUC verbally approved NSP-Minnesota's plan, with modifications as follows:

- The acquisition of at least 1,000 MW of wind by 2019, with additional acquisitions dependent on considerations such as price, bidder qualifications, rate impact, transmission availability and location;
- The acquisition of 650 MW of solar before 2021 through the community solar gardens program or other acquisitions - and pursuit of additional, cost-effective solar resources if it is in the best interests of its customers;
- Determination of the proper mix of purchased power and Company-owned renewable resources shall be made during the resource acquisition process;
- Retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and a finding that more likely than not, there will be a need for approximately 750 MW of capacity coinciding with the retirement of Sherco Unit 1 in 2026;
- Authorization for NSP-Minnesota to file a petition for a certificate of need to select the resource that best meets the system resource and local reliability needs associated with the retirement of Sherco Unit 1 in 2026;
- Acquisition of no less than 400 MW of additional demand response by 2023; and
- Submission of NSP-Minnesota's next Resource Plan by February 2019.

The MPUC's order on NSP-Minnesota's Resource Plan is expected in late 2016.

NSP-Minnesota – Request for Proposal (RFP) — In September 2016, NSP-Minnesota issued a RFP for 1,500 MW of wind generation to be in service by 2020. The RFP requests both Power Purchase Agreements and Build-Own-Transfer proposals. NSP-Minnesota intends to compare self-build options to the RFP bids to ensure that all resource additions are cost-competitive.

In October 2016, NSP-Minnesota submitted a petition for approval to the MPUC of a 750 MW self-build wind farm portfolio. RFP bids were received in October 2016 and will be evaluated in conjunction with the self-build proposal.

An overview of the anticipated RFP schedule is as follows:

- Project proposal selection and negotiation will occur from November 2016 to March 2017;
- A NSP-Minnesota recommendation for proposed wind additions to the MPUC in the first quarter of 2017; and
- MPUC approval is expected by July 2017.

NSP-Wisconsin – Wisconsin 2017 Electric and Gas Rate Case — In April 2016, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) for an increase in annual electric rates of $17.4 million, or 2.4 percent, and an increase in natural gas rates by $4.8 million, or 3.9 percent, effective January 2017.

The electric rate request is for the limited purpose of recovering increases in (1) generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with NSP-Minnesota, and (2) costs associated with forecasted average rate base of $1.188 billion in 2017.

The natural gas rate request is for the limited purpose of recovering expenses related to the ongoing environmental remediation of a former manufactured gas plant site and adjacent area in Ashland, Wis.

No changes are being requested to the capital structure or the 10.0 percent ROE authorized by the PSCW in the 2016 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap, solely for 2017, in which 100 percent of the earnings in excess of the authorized ROE would be refunded to customers.

In August 2016, the PSCW Staff (Staff) and the intervenors filed their direct testimony in the case. The Staff recommended an electric rate increase of $19.5 million, or 2.7 percent and a natural gas rate increase of $4.8 million, or 3.9 percent. The Staff adjustments reflect revisions to previously forecasted rate base as well as fuel and purchased power expense. The Staff's recommended rate increase also encompasses the PSCW's July 2016 decision to remove the $9.5 million fuel refund credit from the rate case and refund that amount directly to customers in 2016. Adjusting for the treatment of the fuel refund, the Staff's recommendation is $7.4 million less than NSP-Wisconsin's request.

On Oct. 26, 2016, the PSCW verbally approved an electric rate increase of approximately $22.5 million, or 3.2 percent, and a natural gas rate increase of $4.8 million, or 3.9 percent. The difference between the Staff's recommendation and the PSCW's approved electric increase is attributable to an increase in forecasted fuel and purchased power expense. Consistent with long-standing PSCW policy, these costs were updated prior to the PSCW's decision to reflect current market forecasts. The PSCW approved NSP-Wisconsin's requested natural gas rate increase consistent with the Staff's recommendation.

The major components of the retail electric rate increase, the Staff's recommendation, and the PSCW's approval are summarized below:

Electric Rate Request (Millions of Dollars)	NSP-Wisconsin Request	Staff Recommendation	Final Decision
Rate base investments	$ 11.0	$ 7.6	7.6
Generation and transmission expenses (excluding fuel and purchased power) [(a)]	6.8	6.1	6.1
Fuel and purchased power expenses	11.0	7.7	10.7
Subtotal	28.8	21.4	24.4
2015 fuel refund [(b)]	(9.5)	—	—
DOE settlement refund	(1.9)	(1.9)	(1.9)
Total electric rate increase	$ 17.4	$ 19.5	$ 22.5

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

(b) In July 2016, the PSCW required NSP-Wisconsin to return the 2015 fuel refund directly to customers, rather than using it to offset the proposed 2017 rate increase, as originally proposed by NSP-Wisconsin. This decision, when combined with the increase in forecasted fuel and purchased power expense, effectively increases NSP-Wisconsin's requested electric rate increase to $29.9 million, or 4.2 percent.

NSP-Wisconsin anticipates a final written order later this year, with new rates effective on Jan. 1, 2017.

PSCo – Rush Creek Wind Ownership Proposal — In May 2016, PSCo filed an application to build, own and operate a 600 MW wind generation facility at Rush Creek for a cost of approximately $1 billion, including transmission investment.

In September 2016, the Colorado Public Utilities Commission (CPUC) approved a settlement between PSCo, the CPUC Staff, the Colorado Office of Consumer Counsel, the Colorado Energy Office and various other parties. This will allow PSCo to commence the project on a timely basis and capture the full production tax credit benefit for customers.

Key terms of the settlement are listed below:

- The Rush Creek project satisfies the reasonable cost standard and is in the public interest;
- The project should be placed in service by Oct. 31, 2018;
- The useful life of the project should be set at 25 years;
- A hard cost-cap on the $1.096 billion investment (which includes the capital investment and allowance for funds used during construction);
- A capital cost sharing mechanism for every $10 million below the cost-cap, with 82.5 percent retained by customers and 17.5 percent retained by PSCo on a net present value basis over the life of the project;
- Amounts retained by PSCo under the capital cost sharing mechanism as well as overall facility revenue requirements may each be reduced for lower than projected long term generating output (i.e., higher degradation); and
- The Pawnee-Daniels transmission line (estimated project cost of $178 million) should be accelerated and operations are expected to begin by October 2019.

PSCo – Decoupling Filing — In July 2016, PSCo filed a request with the CPUC to approve a partial decoupling mechanism for a five year period, effective on Jan. 1, 2017. The proposed decoupling adjustment would allow PSCo to adjust annual revenues based on changes in weather normalized average use per customer for the residential and small C&I classes. The proposed mechanism is intended to improve PSCo's ability to collect base rate revenues in the event that average use per customer declines as a result of DSM, distributed generation and other energy saving programs. The proposed decoupling mechanism is symmetric and may result in potential refunds to customers if there were an increase in average use per customer. PSCo did not request that revenue be adjusted as a result of weather related sales fluctuations.

In August 2016, a majority of the parties to the PSCo Global Settlement Agreement agreed to limit any future opposition to PSCo's decoupling proposal to the specifics of design and implementation.

The key dates in the procedural schedule are as follows:

- Direct testimony — Dec. 14, 2016;
- Answer testimony — Jan. 16, 2017;
- Rebuttal and cross answer testimony — Feb. 10, 2017; and
- Hearings — Feb. 21-24, 2017.

A decision is anticipated in the first quarter of 2017.

SPS – Texas 2016 Electric Rate Case — In February 2016, SPS filed a retail electric, non-fuel rate case in Texas with each of its Texas municipalities and the Public Utility Commission of Texas (PUCT) requesting an overall increase in annual base rate revenue of approximately $71.9 million, or 14.4 percent. The filing is based on a historic test year (HTY) ended Sept. 30, 2015, a requested ROE of 10.25 percent, an electric rate base of approximately $1.7 billion, and an equity ratio of 53.97 percent. In SPS' required update filing in April 2016, SPS revised its requested rate increase to $68.6 million.

Pursuant to legislation passed in Texas in 2015, the final rates established in the case will be effective retroactive to July 20, 2016.

In August 2016, several intervenors filed direct testimony in response to SPS' rate request, including: PUCT Staff (Staff), the Alliance of Xcel Municipalities (AXM), the Office of Public Utility Counsel (OPUC), Texas Industrial Energy Consumers (TIEC), and the State of Texas' agencies.

- The Staff recommended a rate increase of approximately $32.9 million, based on a ROE of 9.30 percent and an equity ratio of 51 percent. The Staff's proposed rate increase reflects imputed revenues for power factor adjustment charges and weather normalization;
- AXM recommended a rate increase of approximately $25.2 million, based on a ROE of 9.40 percent and an equity ratio of 51 percent; and
- The other intervenors did not present a complete revenue requirement analysis. The majority of the direct testimony focused on specific cost allocation and rate design issues. However, OPUC and TIEC recommended ROEs of 9.20 percent and 9.15 percent, respectively.

In October 2016, SPS and various parties reached an agreement in principle in the Texas rate case. SPS and the parties are documenting the settlement, and expect to file with the PUCT in the fourth quarter of 2016. Any settlement would require approval of the PUCT, with a decision expected by the end of 2016 or early 2017.

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) seeking an increase in non-fuel base rates of $45.4 million. The proposed increase would be offset by a decrease in base fuel revenue of approximately $21.1 million. The rate filing was based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric rate base of approximately $734 million and an equity ratio of 53.97 percent.

In August 2016, the NMPRC approved a black-box stipulation that resulted in a non-fuel base rate increase of $23.5 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments to the fuel and purchased power cost adjustment clause.

SPS plans to file another base rate case in November 2016 utilizing a future test year ending June 2018.

Note 5. Xcel Energy Earnings Guidance and Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy 2016 Earnings Guidance — Xcel Energy's narrowed 2016 ongoing earnings guidance is $2.17 to $2.22 per share, compared with the previous issued guidance of $2.12 to $2.27 per share.[a] Key assumptions related to 2016 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to be relatively flat.
- Weather-normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $35 million to $45 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 1 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $185 million to $195 million over 2015 levels. Approximately $20 million of the increased depreciation expense and amortization will be recovered through the renewable development fund rider (not included in the capital rider) in Minnesota.
- Property taxes are projected to increase approximately $20 million to $25 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $50 million to $60 million over 2015 levels.
- AFUDC — equity is projected to increase approximately $0 million to $10 million from 2015 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

Xcel Energy 2017 Earnings Guidance — Xcel Energy's 2017 ongoing earnings guidance is $2.25 to $2.35 per share.[a] Key assumptions related to 2017 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase 0 percent to 0.5 percent.
- Weather-normalized retail firm natural gas sales are projected to increase 0 percent to 0.5 percent.
- Capital rider revenue is projected to increase by $65 million to $75 million over 2016 levels.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately $160 million to $170 million over 2016 levels.
- Property taxes are projected to increase approximately $0 million to $10 million over 2016 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $5 million to $15 million over 2016 levels.
- AFUDC — equity is projected to increase approximately $10 million to $20 million from 2016 levels.
- The ETR is projected to be approximately 32 percent to 34 percent.
- Average common stock and equivalents are projected to be approximately 509 million shares.

(a) Given the unplanned and/or unknown nature of adjustments that may be necessary to reconcile ongoing diluted EPS to GAAP diluted EPS, Xcel Energy is unable to 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 4 percent to 6 percent, based on ongoing 2015 EPS of $2.10;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

Note 6. Non-GAAP Reconciliation

Xcel Energy's reported earnings are prepared in accordance with GAAP. Xcel Energy's management believes that ongoing earnings, or GAAP earnings adjusted for certain items, reflect management's performance in operating the company and provides a meaningful representation of the underlying performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

The following table provides a reconciliation of ongoing earnings to GAAP earnings (net income):

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	**2016**	**2015**	**2016**	**2015**
Ongoing earnings	$ 457,795	$ 426,463	$ 895,902	$ 854,610
Loss on Monticello LCM/EPU project	—	—	—	(79,150)
GAAP earnings	$ 457,795	$ 426,463	$ 895,902	$ 775,460

Loss on Monticello LCM/EPU Project — In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment for years 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million, or $79 million net of tax, in the first quarter of 2015. Given the nature of this specific item, it has been excluded from ongoing earnings.

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

	Three Months Ended Sept. 30	
	2016	2015
Operating revenues:		
Electric and natural gas	$ 3,021,920	$ 2,883,499
Other	18,227	17,813
Total operating revenues	3,040,147	2,901,312
Net income	$ 457,795	$ 426,463
Weighted average diluted common shares outstanding	509,566	508,427
Components of EPS — Diluted		
Regulated utility	$ 0.94	$ 0.87
Xcel Energy Inc. and other costs	(0.04)	(0.03)
Ongoing diluted EPS	**0.90**	**0.84**
Loss on Monticello LCM/EPU project [a]	—	—
GAAP diluted EPS	**$ 0.90**	**$ 0.84**

	Nine Months Ended Sept. 30	
	2016	2015
Operating revenues:		
Electric and natural gas	$ 8,255,769	$ 8,321,949
Other	56,500	56,716
Total operating revenues	8,312,269	8,378,665
Net income	$ 895,902	$ 775,460
Weighted average diluted common shares outstanding	509,396	507,976
Components of EPS — Diluted		
Regulated utility	$ 1.87	$ 1.77
Xcel Energy Inc. and other costs	(0.11)	(0.08)
Ongoing diluted EPS	**1.76**	**1.69**
Loss on Monticello LCM/EPU project [a]	—	(0.16)
GAAP diluted EPS	**$ 1.76**	**$ 1.53**
Book value per share	$ 21.63	$ 20.79

[a] See Note 6.