Jan. 28, 2016

414 Nicollet Mall
Minneapolis, MN 55401

XCEL ENERGY
2015 YEAR END EARNINGS REPORT

- Ongoing 2015 earnings per share were $2.09 compared with $2.03 per share in 2014.
- GAAP (generally accepted accounting principles) 2015 earnings per share were $1.94 compared with $2.03 per share in 2014.
- Xcel Energy reaffirms 2016 ongoing earnings guidance of $2.12 to $2.27 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2015 GAAP earnings of $984 million, or $1.94 per share, compared with 2014 GAAP earnings of $1,021 million, or $2.03 per share.

Ongoing earnings, which exclude adjustments for certain items, were $2.09 per share for 2015 compared with $2.03 per share in 2014. Ongoing earnings increased primarily due to rate increases in various jurisdictions, non-fuel riders, a lower earnings test refund in Colorado and a decline in operating and maintenance expenses. These positive factors were partially offset by the impact of negative weather (seven cents per share) as well as higher depreciation, property taxes, interest charges and lower allowance for fund used for construction.

This is the eleventh consecutive year, Xcel Energy has met or exceeded its earnings guidance, and the twelfth consecutive year the company has increased its dividend.

"I am pleased with our 2015 results," stated Ben Fowke, Chairman, President and Chief Executive Officer. "We delivered earnings within our guidance range despite negative weather and certain regulatory challenges. We were able to accomplish this by reducing O&M expenses and taking other management actions."

"We are proud of our long track record of delivering financial results that are worthy of the trust our investors place in us," said Fowke. "Strong fundamentals, a committed workforce and solid, consistent performance are the hallmark of Xcel Energy."

Xcel Energy reaffirms its 2016 ongoing earnings guidance of $2.12 to $2.27 per share, which is dependent on the key assumptions listed in Note 5.

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 Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2015**	**2014**	**2015**	**2014**
Ongoing diluted EPS	$ **0.41**	$ **0.39**	$ **2.09**	$ **2.03**
Loss on Monticello life cycle management/extended power uprate project [(a)]	—	—	(0.16)	—
GAAP diluted EPS [(b)]	$ **0.41**	$ **0.39**	$ **1.94**	$ **2.03**

(a) See Note 6.
(b) Amounts may not add due to rounding.

At 9:00 a.m. CST 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) 542-1139
International Dial-In:	(719) 457-2084
Conference ID:	534445

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. CST on Jan. 28 through 10:59 p.m. CST on Jan. 29.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	534445

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 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, 2014, 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 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 Dec. 31		Twelve Months Ended Dec. 31	
	2015	2014	2015	2014
Operating revenues				
Electric	$ 2,170,183	$ 2,250,191	$ 9,275,986	$ 9,465,890
Natural gas	455,935	657,274	1,672,081	2,142,738
Other	19,703	21,163	76,419	77,507
Total operating revenues	2,645,821	2,928,628	11,024,486	11,686,135
Operating expenses				
Electric fuel and purchased power	893,390	1,021,644	3,762,953	4,210,142
Cost of natural gas sold and transported	239,685	438,406	904,794	1,372,479
Cost of sales — other	9,800	9,569	36,216	34,352
Operating and maintenance expenses	583,577	620,241	2,329,670	2,334,379
Conservation and demand side management program expenses	59,419	78,220	224,679	301,772
Depreciation and amortization	296,703	262,400	1,124,524	1,019,045
Taxes (other than income taxes)	122,237	106,898	511,675	465,836
Loss on Monticello life cycle management/extended power uprate project	—	—	129,463	—
Total operating expenses	2,204,811	2,537,378	9,023,974	9,738,005
Operating income	441,010	391,250	2,000,512	1,948,130
Other (expense) income, net	(348)	609	5,400	5,296
Equity earnings of unconsolidated subsidiaries	10,030	7,501	34,390	30,151
Allowance for funds used during construction — equity	15,208	20,898	55,936	89,750
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,357, $5,842, $24,175, and $22,986, respectively	153,554	144,895	595,282	566,608
Allowance for funds used during construction — debt	(6,908)	(8,793)	(26,248)	(38,402)
Total interest charges and financing costs	146,646	136,102	569,034	528,206
Income before income taxes	319,254	284,156	1,527,204	1,545,121
Income taxes	110,229	87,817	542,719	523,815
Net income	$ 209,025	$ 196,339	$ 984,485	$ 1,021,306
Weighted average common shares outstanding:				
Basic	508,312	506,411	507,768	503,847
Diluted	508,738	506,799	508,168	504,117
Earnings per average common share:				
Basic	$ 0.41	$ 0.39	$ 1.94	$ 2.03
Diluted	0.41	0.39	1.94	2.03
Cash dividends declared per common share	$ 0.32	$ 0.30	$ 1.28	$ 1.20

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 as well as the return on equity (ROE) 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 and ongoing ROE for Xcel Energy and by subsidiary are financial measures 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 nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average common stockholders' or stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2015**	**2014**	**2015**	**2014**
Public Service Company of Colorado (PSCo)	$ 0.16	$ 0.18	$ 0.92	$ 0.90
NSP-Minnesota	0.20	0.17	0.85	0.80
Southwestern Public Service Company (SPS)	0.04	0.03	0.25	0.26
NSP-Wisconsin	0.03	0.03	0.15	0.14
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.04
Regulated utility	0.44	0.42	2.21	2.14
Xcel Energy Inc. and other	(0.03)	(0.03)	(0.11)	(0.11)
Ongoing diluted EPS [(a)]	0.41	0.39	2.09	2.03
Loss on Monticello life cycle management (LCM)/ extended power uprate (EPU) project [(b)]	—	—	(0.16)	—
GAAP diluted EPS [(a)]	**$ 0.41**	**$ 0.39**	**$ 1.94**	**$ 2.03**

(a) Amounts may not add due to rounding.
(b) See Note 6.

PSCo — PSCo's ongoing earnings increased $0.02 per share for 2015. Higher revenue primarily due to the Clean Air Clean Jobs Act (CACJA) rider (partially offset by an electric base rate decrease), as well as a natural gas rate increase (interim, subject to refund) effective in October 2015, lower estimated electric earnings test refunds and the positive impact of weather. These positive factors were partially offset by higher property taxes, depreciation, operating and maintenance (O&M) expenses, interest charges and lower allowance for funds used during construction (AFUDC).

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.05 per share for 2015. Ongoing earnings were positively impacted by electric rate increases in Minnesota, North Dakota and South Dakota, and lower O&M expenses. These positive factors were partially offset by unfavorable weather, sales decline, higher depreciation, increased interest charges, property taxes and lower AFUDC.

SPS — SPS' ongoing earnings decreased $0.01 per share for 2015. Although Texas electric rates rose as a result of the prior year rate case, this was reduced by the negative impact of the 2015 case. The net increase in electric rates was more than offset by additional depreciation, higher O&M expenses and lower AFUDC.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.01 per share for 2015. Higher electric revenues primarily driven by an electric rate increase and lower O&M expenses were partially offset by higher depreciation and lower natural gas margins.

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014:

Diluted Earnings (Loss) Per Share	Three Months Ended Dec. 31	Twelve Months Ended Dec. 31
2014 GAAP and ongoing diluted EPS	**$ 0.39**	**$ 2.03**
Components of change — 2015 vs. 2014		
Higher electric margins	0.06	0.31
Lower conservation and demand side management (DSM) program expenses	0.02	0.09
Lower O&M expenses	0.04	0.01
Higher depreciation and amortization	(0.04)	(0.13)
Lower AFUDC — equity	(0.01)	(0.07)
Higher effective tax rate (ETR)	(0.02)	(0.06)
Higher taxes (other than income taxes)	(0.02)	(0.06)
Higher interest charges	(0.01)	(0.03)
Other, net	—	0.01
2015 ongoing diluted EPS [a]	**0.41**	**2.09**
Loss on Monticello LCM/EPU project [b]	—	(0.16)
2015 GAAP diluted EPS [a]	**$ 0.41**	**$ 1.94**

ROE — 2015	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies [c]	Xcel Energy [c]
2015 ongoing ROE	9.33%	8.72%	7.56%	10.45%	8.91%	10.22%
Loss on Monticello LCM/ EPU project [b]	—	(1.49)	—	(0.42)	(0.62)	(0.76)
2015 GAAP ROE	9.33%	7.23%	7.56%	10.03%	8.29%	9.46%

ROE — 2014	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Operating Companies [c]	Xcel Energy [c]
2014 ongoing and GAAP ROE	9.40%	8.82%	8.88%	10.85%	9.18%	10.33%

(a) Amounts may not add due to rounding.
(b) See Note 6.
(c) Excluding the impact of negative/positive weather, the Operating Companies and Xcel Energy's ongoing ROEs equate to 9.07 percent and 10.40 percent, respectively, for 2015 and 9.06 percent and 10.18 percent, respectively, for 2014.

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 cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. 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 are provided in the following table:

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(14.1)%	1.8%	(15.7)%	(7.9)%	7.8%	(14.8)%
CDD [a]	N/A	N/A	N/A	6.2	(2.6)	10.3
THI [a]	N/A	N/A	N/A	(2.3)	(11.9)	14.1

[a] CDD and THI have no meaningful impact on fourth quarter sales.

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

	Three Months Ended Dec. 31			Twelve Months Ended Dec. 31		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
Retail electric	$ (0.016)	$ —	$ (0.016)	$ (0.020)	$ 0.010	$ (0.030)
Firm natural gas	(0.011)	0.001	(0.012)	(0.018)	0.019	(0.037)
Total	$ (0.027)	$ 0.001	$ (0.028)	$ (0.038)	$ 0.029	$ (0.067)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2015:

	Three Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	3.1%	(4.0)%	(0.6)%	(10.5)%	(1.4)%
Electric commercial and industrial	(1.5)	(1.5)	1.5	(2.3)	(0.9)
Total retail electric sales	(0.1)	(2.2)	1.0	(4.7)	(1.0)
Firm natural gas sales	(1.7)	(20.9)	N/A	(25.6)	(9.2)

	Three Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [a]	2.0%	0.9%	(0.7)%	(3.9)%	0.7%
Electric commercial and industrial	(1.8)	(1.0)	1.7	(1.5)	(0.7)
Total retail electric sales	(0.6)	(0.5)	1.1	(2.2)	(0.3)
Firm natural gas sales	(1.5)	(1.2)	N/A	(5.4)	(1.7)

	Twelve Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential [a]	1.1%	(3.2)%	(0.4)%	(6.1)%	(1.4)%
Electric commercial and industrial	(0.4)	(0.6)	0.3	0.4	(0.2)
Total retail electric sales	0.1	(1.4)	0.1	(1.5)	(0.6)
Firm natural gas sales	(6.6)	(16.6)	N/A	(16.4)	(10.5)

	Twelve Months Ended Dec. 31				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential [(a)]	0.4%	(0.7)%	0.6%	(2.8)%	(0.3)%
Electric commercial and industrial	(0.9)	(0.2)	0.7	0.8	(0.1)
Total retail electric sales	(0.5)	(0.4)	0.5	(0.3)	(0.2)
Firm natural gas sales	(2.0)	(1.1)	N/A	(1.7)	(1.7)

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

Weather-normalized Electric 2015 Growth (Decline)

- PSCo's residential growth was primarily the result of customer additions, partially offset by lower use per customer. Commercial and industrial (C&I) decline was primarily due to reduced sales to certain large manufacturing customers and/or those that support the fracking industry.
- NSP-Minnesota's residential decrease was due to lower use per customer, partially offset by an increase in customer additions. C&I electric sales decreased as a result of lower use by large and small customers (e.g., services, retail trade, finance insurance and real estate industries), partially offset by higher use by certain large customers in the petroleum and food processing industries. The decline was partially reduced by an increase in the number of customers in both the small and large classes.
- SPS' residential growth reflects an increased number of customers. C&I also had an increase in customers, primarily in the oil and gas exploration and production industries. However, this was partially offset by reduced activity per customer within these industries, as well as less irrigation by agricultural customers due to wet weather.
- NSP-Wisconsin's residential decline was primarily attributable to lower use per customer, partially offset by customer additions. C&I electric sales growth was largely due to strong sales to large customers primarily in the oil and gas industries.

Weather-normalized Natural Gas 2015 Decline

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

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:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	2015	2014	2015	2014
Electric revenues	$ 2,170	$ 2,250	$ 9,276	$ 9,466
Electric fuel and purchased power	(893)	(1,022)	(3,763)	(4,210)
Electric margin	$ 1,277	$ 1,228	$ 5,513	$ 5,256

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

(Millions of Dollars)	Three Months Ended Dec. 31 2015 vs. 2014	Twelve Months Ended Dec. 31 2015 vs. 2014
Retail rate increases [a]	$ 21	$ 101
Colorado CACJA non-fuel rider	20	94
PSCo earnings test refunds	13	74
Transmission revenue, net of costs	19	47
Non-fuel riders [b]	8	20
Conservation and DSM program revenues (offset by expenses)	(16)	(62)
Estimated impact of weather	(12)	(23)
Other, net	(4)	6
Total increase in electric margin	$ 49	$ 257

[a] Increase due to rate proceedings in Minnesota, South Dakota, Texas, North Dakota, New Mexico and Wisconsin. These increases were partially offset by a decline in Colorado retail base rates, which was more than offset by increased CACJA rider revenue.

[b] Primarily related to the Transmission Cost Recovery rider in Minnesota.

Natural Gas Margin — Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. 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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	2015	2014	2015	2014
Natural gas revenues	$ 456	$ 657	$ 1,672	$ 2,143
Cost of natural gas sold and transported	(240)	(438)	(905)	(1,372)
Natural gas margin	$ 216	$ 219	$ 767	$ 771

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

(Millions of Dollars)	Three Months Ended Dec. 31 2015 vs. 2014	Twelve Months Ended Dec. 31 2015 vs. 2014
Estimated impact of weather	$ (10)	$ (30)
Conservation and DSM program revenues (offset by expenses)	(2)	(13)
Infrastructure and integrity riders, partially offset in O&M expenses	5	30
Purchased gas adjustment	—	5
Retail rate increases (Colorado, interim, subject to refund)	4	4
Total decrease in natural gas margin	$ (3)	$ (4)

O&M Expenses — O&M expenses decreased $36.7 million, or 5.9 percent, for the fourth quarter of 2015 and $4.7 million, or 0.2 percent, for 2015 compared with the same periods in 2014. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended Dec. 31 2015 vs. 2014	Twelve Months Ended Dec. 31 2015 vs. 2014
Nuclear plant operations	$ (15)	$ (22)
Transmission costs	(2)	(4)
Labor and contract labor	3	14
Plant generation costs	(12)	1
Other, net	(11)	6
Total decrease in O&M expenses	$ (37)	$ (5)

Changes in annual O&M expenses were due to the following:

- Nuclear expense decreased primarily driven by operational efficiencies and lower amortization of prior outages; and
- Labor and contract labor increased as a result of various projects and initiatives to improve business processes.

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $18.8 million, or 24.0 percent, for the fourth quarter of 2015 and $77.1 million, or 25.5 percent, for 2015 compared with the same periods in 2014. The decreases were primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Lower conservation and DSM program expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization increased $34.3 million, or 13.1 percent, for the fourth quarter of 2015 and $105.5 million, or 10.4 percent, for 2015 compared with the same periods in 2014. Increases were primarily attributed to capital investments and lower amortization of the excess depreciation reserve in Minnesota, partially offset by Minnesota's amortization of the Department of Energy settlement.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $15.3 million, or 14.3 percent, for the fourth quarter of 2015 and $45.8 million, or 9.8 percent, for 2015 compared with the same periods in 2014. Increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $7.6 million for the fourth quarter of 2015 and $46.0 million for 2015 compared with the same periods in 2014. Decreases were primarily due to the implementation of the CACJA rider, facilitating earlier and alternative recovery of construction costs.

Interest Charges — Interest charges increased $8.7 million, or 6.0 percent, for the fourth quarter of 2015 and $28.7 million, or 5.1 percent, for 2015 compared with the same periods in 2014. Increases were primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense increased $22.4 million for the fourth quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher pretax earnings in 2015 and a higher tax benefit for a carryback claim in 2014. The effective tax rate (ETR) was 34.5 percent for the fourth quarter of 2015 compared with 30.9 percent for the same period in 2014. The lower ETR for 2014 was primarily due to the tax benefit for the carryback.

Income tax expense increased $18.9 million for 2015 compared with 2014. The increase was primarily due to a higher tax benefit for a carryback claim in 2014 and decrease in permanent plant-related deductions (e.g., AFUDC-equity) in 2015. The ETR was 35.5 percent for 2015 compared with 33.9 percent for 2014. The difference between periods was primarily due to the permanent plant-related deductions and the tax benefit for a carryback claim in 2014.

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

Following is the capital structure of Xcel Energy:

	As of December 31, 2015		As of December 31, 2014	
(Billions of Dollars)	Capital Structure	Percentage of Total Capitalization	Capital Structure	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.7	3%	$ 0.3	1%
Short-term debt	0.8	3	1.0	4
Long-term debt	12.5	51	11.5	50
Total debt	14.0	57	12.8	55
Common equity	10.6	43	10.2	45
Total capitalization	$ 24.6	100%	$ 23.0	100%

Credit Facilities — As of Jan. 25, 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	$ 554	$ 446	$ —	$ 446
PSCo	700	158	542	1	543
SPS	400	91	309	—	309
NSP-Minnesota	500	371	129	1	130
NSP-Wisconsin	150	38	112	1	113
Total	$ 2,750	$ 1,212	$ 1,538	$ 3	$ 1,541

(a) These credit facilities mature in October 2019.
(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).

As of Jan. 25, 2016, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

Company	Credit Type	Moody's	Standard & Poor's	Fitch
Xcel Energy Inc.	Senior Unsecured Debt	A3	BBB+	BBB+
Xcel Energy Inc.	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A2	A-	A
NSP-Minnesota	Senior Secured Debt	Aa3	A	A+
NSP-Minnesota	Commercial Paper	P-1	A-2	F2
NSP-Wisconsin	Senior Unsecured Debt	A2	A-	A
NSP-Wisconsin	Senior Secured Debt	Aa3	A	A+
NSP-Wisconsin	Commercial Paper	P-1	A-2	F2
PSCo	Senior Unsecured Debt	A3	A-	A
PSCo	Senior Secured Debt	A1	A	A+
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa1	A-	BBB+
SPS	Senior Secured Debt	A2	A	A-
SPS	Commercial Paper	P-2	A-2	F2

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.

Capital Expenditures — The actual and current estimated base capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2020 are shown in the table below.

	Actual	Base Capital Forecast					
(Millions of Dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2016 - 2020 Total**
By Subsidiary							
NSP-Minnesota	$ 1,753	$ 1,290	$ 1,050	$ 1,215	$ 1,245	$ 1,125	$ 5,925
PSCo	944	975	940	960	1,030	1,070	4,975
SPS	602	560	725	640	520	450	2,895
NSP-Wisconsin	230	225	250	295	265	285	1,320
Other	—	10	10	10	10	10	50
Total capital expenditures	$ 3,529	$ 3,060	$ 2,975	$ 3,120	$ 3,070	$ 2,940	$ 15,165

	Actual	Base Capital Forecast					
(Millions of Dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2016 - 2020 Total**
By Function							
Electric transmission	$ 889	$ 700	$ 825	$ 875	$ 855	$ 870	$ 4,125
Electric distribution	639	645	775	790	915	940	4,065
Electric generation	1,230	835	510	565	470	465	2,845
Natural gas	368	390	335	395	390	400	1,910
Nuclear fuel	90	120	120	60	145	85	530
Minnesota Integrated Resource Plan renewables	—	—	120	250	110	—	480
Other	313	370	290	185	185	180	1,210
Total capital expenditures	$ 3,529	$ 3,060	$ 2,975	$ 3,120	$ 3,070	$ 2,940	$ 15,165

In addition, Xcel Energy has potential incremental capital investment opportunities that could increase the base capital forecast by $2.5 billion over the 2016-2020 timeframe. This would result in a total capital forecast of $17.7 billion for 2016-2020.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility 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.

PSCo Natural Gas Reserves Investments — In January 2016, PSCo filed a request with the CPUC for approval of a long-term natural gas procurement and price hedging framework. Under the proposal a wholly-owned subsidiary of PSCo, PSCo Gas Reserves Company (PGRCo), will be formed to partner with Wexpro Development Company (Wexpro), a subsidiary of Questar Corporation, to acquire, develop and operate natural gas producing properties on a 50/50 joint basis, with production recovered under cost of service pricing through PSCo's Gas Cost Adjustment. The CPUC has 240 days to review the proposed framework. If approved, PGRCo may invest up to approximately $500 million in gas properties over 10 years, which is not reflected in the current base capital expenditures forecast.

The requested cost of service pricing formulas provide PGRCo and Wexpro different risks and incentives. For PGRCo, the investment would include all costs of property acquisition and development. The ROE would be based on PSCo's allowed ROE, adjusted up or down a maximum of 100 basis points, based on the price of gas produced relative to market prices.

Following approval of the framework, PSCo and Wexpro will seek to identify and acquire specific natural gas producing properties that would be beneficial to PSCo's gas customers, and seek CPUC approval of these specific investments.

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 base capital investment program for 2016-2020. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2016 through 2020 are shown in the table below.

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from Operations*	$	12,400
New Debt**		2,765
Equity		0
2016-2020 Capital Expenditures	$	15,165
Maturing Debt	$	4,165

* Net of dividend and pension funding.
** Reflects a combination of short and long-term debt.

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

- Xcel Energy Inc. plans to issue approximately $700 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately $250 million of first mortgage bonds; and
- SPS plans to issue approximately $350 million of first mortgage bonds.

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

2015 Financing Activity — During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025;
- NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024;
- NSP-Minnesota issued $300 million of 2.2 percent first mortgage bonds due Aug. 15, 2020 and $300 million of 4.0 percent first mortgage bonds due Aug. 15, 2045; and
- SPS issued $200 million of 3.3 percent first mortgage bonds due June 15, 2024.

Note 4. Rates and Regulation

NSP-Minnesota – Minnesota 2016 Multi-Year Electric Rate Case — On Nov. 2, 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 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

NSP-Minnesota also proposed a five-year alternative plan that would extend the rate plan two additional years.

In addition, NSP-Minnesota has requested the MPUC encourage parties to engage in a formal mediation type procedure as outlined by Minnesota's rate case statute which may streamline the settlement process.

In December 2015, the MPUC accepted the rate case and approved interim rates for 2016. The MPUC deferred making a decision on incremental interim rates for 2017 and indicated that NSP-Minnesota could bring back its request in the fourth quarter of 2016. The MPUC also required NSP-Minnesota to file supplemental direct testimony by Jan. 29, 2016, addressing costs to complete the LCM at the Prairie Island nuclear plant.

The next steps in the procedural schedule are expected to be as follows:

- Intervenors' direct testimony — June 14, 2016;
- Rebuttal testimony — Aug. 9, 2016;
- Surrebuttal testimony — Sept. 16, 2016;
- Settlement conference — Sept. 26, 2016;
- Evidentiary hearing — Oct. 4-7, 2016;
- Administrative Law Judge (ALJ) report — Feb. 21, 2017; and
- MPUC order — June 1, 2017.

NSP-Wisconsin – Wisconsin 2016 Electric and Gas Rate Case — In May 2015, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) seeking an increase in annual electric rates of $27.4 million, or 3.9 percent, and an increase in natural gas rates of $5.9 million, or 5.0 percent, effective Jan. 1, 2016. The rate filing was based on a 2016 forecast test year, a ROE of 10.2 percent, an equity ratio of 52.5 percent and a forecasted average rate base of approximately $1.2 billion for the electric utility and $111.2 million for the natural gas utility.

In December 2015, the PSCW approved an electric rate increase of approximately $7.6 million, or 1.1 percent, and a natural gas rate increase of $4.2 million, or 3.6 percent, based on a 10.0 percent ROE and an equity ratio of 52.5 percent. New rates went into effect in January 2016. As shown below, NSP-Wisconsin received approximately 65 percent of the non-fuel and purchased power portion of its requested electric rate increase and 71 percent of its requested natural gas rate increase.

The major components of the requested rate increases and the PSCW's approval are summarized as follows:

Electric Rate Request (Millions of Dollars)	**NSP-Wisconsin Request**	**PSCW Approval**
Capital investments	$ 23.0	$ 13.9
ROE & other capital structure adjustments	—	(3.8)
Generation and transmission expenses (excluding fuel and purchased power)	37.2	42.7
O&M expenses	11.1	3.2
Sales forecast	(27.0)	(27.0)
Rate increase - non-fuel and purchased power	44.3	29.0
Rate reduction - fuel and purchased power	(16.9)	(21.4)
Total electric rate increase	$ 27.4	$ 7.6

Natural Gas Rate Request (Millions of Dollars)	**NSP-Wisconsin Request**	**PSCW Approval**
Capital investments	$ 3.7	$ 3.7
ROE & other capital structure adjustments	—	(0.4)
O&M expenses	3.2	1.9
Environmental remediation expenses	2.9	2.9
Sales forecast	(3.9)	(3.9)
Total natural gas rate increase	$ 5.9	$ 4.2

PSCo – Colorado "Our Energy Future" Plan — The proposal ties together innovative technology, economic development and customer initiatives to give customers more control over their energy use, prepare for the future energy demands of the state and keep rates competitive. The key components of the plan include:

- Two Innovative Clean Technology pilot programs in partnership with leading companies, such as Panasonic Corporation, to address electric battery efficiency and reliability;
- Alignment of PSCo's pricing in a more fair and equitable manner for Colorado customers;
- Introduction of Solar*Connect, a new, cost-based program that will offer customers a choice to sign up for 100 percent solar power and add an incremental 50 megawatts (MW) of solar generation;
- Investing in natural gas reserves to take advantage of historically low natural gas prices by locking in current costs to provide long-term predictable rates for our customers;
- Investigating up to 1,000 MW of additional renewable resources to be presented later this year for consideration by the CPUC; and

- Presenting an intelligent grid proposal later this year focusing on interactive meter technology that will improve customer choice and control of their energy use.

PSCo – Colorado 2015 Multi-Year Gas Rate Case — In March 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by $66.2 million over three years. The request is based on a historic test year (HTY) ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the periods in the multi-year plan (MYP) and an equity ratio of 56 percent. In addition, PSCo requested an extension of its pipeline system integrity adjustment (PSIA) rider through 2020 to recover costs associated with its pipeline integrity efforts. The rider would recover incremental revenue of $42.8 million over three years.

In June 2015, the CPUC Staff (Staff) and the Office of Consumer Counsel (OCC) issued their base rate and PSIA recommendations. The Staff recommended certain adjustments to the PSIA rider. The OCC stated that the PSIA rider should expire on June 30, 2016 and any related costs be included in base rates through a step increase.

In July 2015, PSCo filed rebuttal testimony with adjustments and modified recovery between base rates and the PSIA rider. The revised request is summarized below:

(Millions of Dollars)	2015	2016 Step	2017 Step
PSCo's filed base rate request	$ 40.5	$ 7.6	$ 18.1
Shift O&M expenses between PSIA and base rates	—	7.0	6.4
Rebuttal corrections and adjustments	—	—	(7.7)
Total base rate increase	$ 40.5	$ 14.6	$ 16.8
Incremental PSIA rider revenues	(0.1)	14.7	21.7
Total revenue impact from rebuttal	$ 40.4	$ 29.3	$ 38.5
Requested ROE	10.1%	10.1%	10.3%
Rate base	$ 1,260	$ 1,310	$ 1,360

In November 2015, the ALJ issued his recommended decision, which reflected a 2014 HTY with a 13-month average rate base, the Cherokee pipeline investment adjusted to year-end rate base, a ROE of 9.5 percent and an equity ratio of 56.51 percent. In addition, the ALJ's recommendation included a three-year extension (2016 through 2018) of the PSIA rider with all O&M expenses transferred to base rates as well as certain other projects shifting between the PSIA rider and base rates, beginning January 2016.

The ALJ also recommended that certain expenses, including property taxes and damage prevention costs that exceed the 2014 HTY level, be deferred. He further recommended a pension cost tracker and certain other deferral related items.

The following table summarizes the estimated annual pre-tax impact of the ALJ's recommended decision:

(Millions of Dollars)	2015	2016	2017
Total base rate increase	$ 18.1	$ 20.0	$ —
Incremental PSIA rider revenues	(0.2)	(7.0)	17.6
Expense deferrals	0.2	4.8	9.6
Estimated pre-tax impact	$ 18.1	$ 17.8	$ 27.2

Interim rates, subject to refund, went into effect Oct. 1, 2015. PSCo has recognized management's best estimate of the potential customer refund obligation.

On Jan. 27, 2016, the CPUC held its deliberation meeting. Although no revenue requirement was provided, the CPUC decisions were generally consistent with the ALJ's recommendation. Key matters are as follows:

- 2014 HTY, with a 13-month average rate base, with the exception of the Cherokee pipeline which is included at a year-end level;
- Extension of the PSIA rider through 2018 with all O&M expenses transferred to base rates;
- A ROE of 9.5 percent; and
- An equity ratio of 56.51 percent.

A written order is anticipated later in the first quarter.

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on a HTY ending June 2014, adjusted for known and measurable changes, a ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent.

SPS requested a waiver of the PUCT post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014. In June 2015, SPS revised its requested rate increase to $42.1 million.

In December 2015, the PUCT made the following decisions:

- Disallowed SPS' proposed adjustment to jurisdictional allocation factors to reflect Golden Spread Electric Cooperative, Inc.'s wholesale load reductions from 500 MW to 300 MW, effective June 1, 2015;
- Disallowed incentive compensation;
- Approved an equity ratio of 51.00 percent instead of the actual 53.97 percent; and
- A ROE of 9.70 percent.

The following table reflects the ALJs' position and PUCT's decision.

(Millions of Dollars)	**ALJs' Proposal for Decision**	**PUCT Decision**
SPS' revised rate request	$ 42.1	$ 42.1
Investment for capital expenditures — post-test year adjustments	(8.9)	(8.9)
Lower ROE	(6.3)	(6.3)
Lower capital structure	—	(3.7)
Annual incentive compensation	(0.2)	(0.3)
O&M expense adjustments	(4.6)	(4.6)
Depreciation expense	(2.7)	(2.7)
Property taxes	(0.9)	(0.9)
Revenue adjustments	(1.1)	(1.6)
Wholesale load reductions	—	(11.5)
SPP transmission expansion plan	(4.2)	(4.2)
Other, net	1.4	(1.2)
Total, gross of rate case expenses	$ 14.6	$ (3.8)
Adjustment to move rate case expenses to a separate docket	(0.2)	(0.2)
Total, net of rate case expenses	$ 14.4	$ (4.0)
New depreciation rates	(11.2)	(11.2)
Earnings impact	$ 3.2	$ (15.2)

On Jan. 7, 2016, SPS filed its motion for rehearing on capital structure, incentive compensation and known and measurable adjustments, including wholesale load reductions and post test-year capital additions. The PUCT has 45 days to respond to the request for rehearing.

In addition, SPS expects to file a new rate case in the first quarter of 2016 which will incorporate provisions of the legislation passed in 2015.

SPS – New Mexico 2015 Electric Rate Case — In October 2015, SPS filed a New Mexico electric rate case with the New Mexico Public Regulation Commission (NMPRC) for a net increase in base rates of approximately $24.3 million. The proposed net amount reflects an increase in non-fuel base rates of $45.4 million and a decrease in base fuel revenue of approximately $21.1 million. The decrease in base fuel revenue will be reflected in adjustments collected through the fuel and purchased power adjustment clause. The rate filing is based on a June 30, 2015 HTY adjusted for known and measurable changes, a requested ROE of 10.25 percent, an electric jurisdictional rate base of approximately $734 million and an equity ratio of 53.97 percent.

The major components of the requested rate increase are summarized below:

(Millions of Dollars)	Request
2015 base period deficiency	$ 19.7
Capital expenditures — post-test year adjustments	12.3
Depreciation, higher rates reflecting changes in depreciable lives, interim retirements and net salvage	3.7
Transmission revenue and expense, including charges paid to SPP for construction of regionally shared transmission projects	2.0
ROE, reflecting an increase from 9.96 percent to 10.25 percent	1.6
Rider revenue adjustments - gross receipts tax	1.3
Other, net	4.8
Requested rate increase	$ 45.4

The next steps in the procedural schedule are expected to be as follows:

- Settlement conference — Feb. 18-19, 2016;
- Staff and intervenor direct testimony — April 1, 2016;
- Rebuttal testimony — April 18, 2016; and
- Evidentiary hearing — April 28, 2016.

A NMPRC decision and implementation of final rates is anticipated in the second half of 2016.

In response to the original 2015 electric rate case previously dismissed, SPS has appealed that decision to the New Mexico Supreme Court. A date has not yet been set for oral arguments. SPS anticipates a decision by the first quarter of 2017.

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

Xcel Energy Earnings Guidance — Xcel Energy's 2016 ongoing earnings guidance is $2.12 to $2.27 per share. 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 year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent to 1.0 percent.
- Weather normalized retail firm natural gas sales are projected to be relatively flat.
- Capital rider revenue is projected to increase by $70 million to $80 million over 2015 levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2015 levels.
- Depreciation expense is projected to increase approximately $200 million over 2015 levels.
- Property taxes are projected to increase approximately $40 million to $50 million over 2015 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2015 levels.
- AFUDC — equity is projected to decline approximately $10 million to $15 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.

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, which was the mid-point of Xcel Energy's 2015 ongoing guidance range;
- 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 management believes that ongoing earnings reflects management's performance in operating the company and provides a meaningful representation of the 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.

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Thousands of Dollars)	**2015**	**2014**	**2015**	**2014**
Ongoing earnings	$ 209,025	$ 196,339	$ 1,063,635	$ 1,021,306
Loss on Monticello LCM/EPU project	—	—	(79,150)	—
GAAP earnings	**$ 209,025**	**$ 196,339**	**$ 984,485**	**$ 1,021,306**

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 Dec. 31	
	2015	2014
Operating revenues:		
Electric and natural gas	$ 2,626,118	$ 2,907,465
Other	19,703	21,163
Total operating revenues	2,645,821	2,928,628
Net income	$ 209,025	$ 196,339
Weighted average diluted common shares outstanding	508,738	506,799
Components of EPS — Diluted		
Regulated utility	$ 0.44	$ 0.42
Xcel Energy Inc. and other costs	(0.03)	(0.03)
Ongoing diluted EPS	**0.41**	**0.39**
Loss on Monticello LCM/EPU project [a]	—	—
GAAP diluted EPS	**$ 0.41**	**$ 0.39**

	Twelve Months Ended Dec. 31	
	2015	2014
Operating revenues:		
Electric and natural gas	$ 10,948,067	$ 11,608,628
Other	76,419	77,507
Total operating revenues	11,024,486	11,686,135
Net income	$ 984,485	$ 1,021,306
Weighted average diluted common shares outstanding	508,168	504,117
Components of EPS — Diluted		
Regulated utility	$ 2.21	$ 2.14
Xcel Energy Inc. and other costs	(0.11)	(0.11)
Ongoing diluted EPS [b]	**2.09**	**2.03**
Loss on Monticello LCM/EPU project [a]	(0.16)	—
GAAP diluted EPS	**$ 1.94**	**$ 2.03**
Book value per share	$ 20.89	$ 20.20

[a] See Note 6.
[b] Amounts may not add due to rounding.