414 Nicollet Mall
Minneapolis, MN 55401

Oct. 30, 2014

XCEL ENERGY
THIRD QUARTER 2014 EARNINGS REPORT

- Ongoing 2014 third quarter diluted earnings per share were $0.73 compared with $0.77 in 2013;
- GAAP (generally accepted accounting principles) 2014 and 2013 third quarter diluted earnings per share were $0.73;
- 2014 ongoing earnings expected to be within a revised guidance range of $1.95 to $2.05 per share, compared with the previously stated guidance range of $1.90 to $2.05 per share;
- 2015 ongoing earnings guidance of $2.00 to $2.15 per share initiated; and
- Updated capital expenditure forecast of $14.5 billion for 2015-2019 released.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2014 third quarter GAAP earnings of $369 million, or $0.73 per share, compared with $365 million, or $0.73 per share, in the same period in 2013. On an ongoing basis, which excludes the specified item noted below, earnings totaled $0.77 per share for the 2013 period.

The decrease in ongoing earnings was largely due to the impact of weather, which adversely affected earnings by $0.07 per share. Earnings results also reflect higher electric and natural gas margins due to new rates in various jurisdictions and expected lower operating and maintenance expenses, which were partially offset by higher depreciation and amortization and property taxes.

Third quarter 2013 GAAP earnings included a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013 related to a 2004 complaint regarding the allocation of system average fuel costs and base rates.

"While weather was unfavorable, we had a solid quarter that keeps us on track to achieve our 2014 ongoing earnings guidance and allows us to narrow the range to $1.95 to $2.05 per share," said Chairman, President and Chief Executive Officer Ben Fowke. "Our O&M expenses were down for the quarter and we are positioned to meet our annual O&M growth objective of 2 to 3 percent for 2014. We also made progress in various regulatory proceedings across our jurisdictions. For the pending multi-year Minnesota electric rate case, we reached agreement with stakeholders on several key issues and continue to believe that we will achieve constructive outcomes on the remaining items."

"Looking ahead, the updated capital plan we released today positions us to continue to be competitive and supports an attractive value proposition of 4 to 6 percent annual growth in earnings per share and our dividend. We are also introducing our 2015 ongoing earnings guidance of $2.00 to $2.15 per share," stated Fowke.

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

Diluted Earnings (Loss) Per Share [(a)]	Three Months Ended Sept. 30 2014	Three Months Ended Sept. 30 2013	Nine Months Ended Sept. 30 2014	Nine Months Ended Sept. 30 2013
Ongoing diluted EPS	$ 0.73	$ 0.77	$ 1.64	$ 1.65
SPS 2004 FERC complaint case orders [(b)]	—	(0.04)	—	(0.04)
GAAP diluted EPS	**$ 0.73**	**$ 0.73**	**$ 1.64**	**$ 1.61**

(a) See Note 2.
(b) See Note 7.

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) 205-6702
International Dial-In:	(913) 312-0687
Conference ID:	2735251

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 Investors. 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. 30 through 10:59 p.m. CDT on Oct. 31.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	2735251

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 2014 and 2015 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 do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: 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 Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; 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; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the Nuclear Regulatory Commission; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations in Item 7 of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2013; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013 and Quarterly Reports on Form 10-Q for the quarters ended March 31 and June 30, 2014.

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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	
	2014	2013	2014	2013
Operating revenues				
Electric	$ 2,616,351	$ 2,599,925	$ 7,215,699	$ 6,911,998
Natural gas	236,649	205,358	1,485,464	1,216,275
Other	16,807	17,055	56,344	55,827
Total operating revenues	2,869,807	2,822,338	8,757,507	8,184,100
Operating expenses				
Electric fuel and purchased power	1,079,855	1,097,944	3,188,498	3,034,031
Cost of natural gas sold and transported	99,344	74,847	934,073	702,987
Cost of sales — other	8,012	7,540	24,783	23,832
Operating and maintenance expenses	568,391	575,305	1,714,138	1,667,093
Conservation and demand side management program expenses	75,172	67,811	223,552	192,288
Depreciation and amortization	255,395	228,491	756,645	721,131
Taxes (other than income taxes)	117,958	105,287	358,938	320,765
Total operating expenses	2,204,127	2,157,225	7,200,627	6,662,127
Operating income	665,680	665,113	1,556,880	1,521,973
Other income (expense), net	1,404	(404)	4,687	3,931
Equity earnings of unconsolidated subsidiaries	7,401	7,273	22,650	22,379
Allowance for funds used during construction — equity	23,337	21,284	68,852	63,147
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,737, $6,020, $17,144 and $24,058, respectively	143,219	144,542	421,713	431,026
Allowance for funds used during construction — debt	(9,948)	(9,377)	(29,609)	(28,451)
Total interest charges and financing costs	133,271	135,165	392,104	402,575
Income before income taxes	564,551	558,101	1,260,965	1,208,855
Income taxes	195,969	193,349	435,998	410,676
Net income	$ 368,582	$ 364,752	$ 824,967	$ 798,179
Weighted average common shares outstanding:				
Basic	506,082	498,149	502,983	495,256
Diluted	506,365	498,641	503,213	495,767
Earnings per average common share:				
Basic	$ 0.73	$ 0.73	$ 1.64	$ 1.61
Diluted	0.73	0.73	1.64	1.61
Cash dividends declared per common share	$ 0.30	$ 0.28	$ 0.90	$ 0.83

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 earnings per share 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 and 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. We use this non-GAAP financial measure to evaluate and provide details of earnings results. We believe this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. 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 the diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	**2014**	**2013**	**2014**	**2013**
Public Service Company of Colorado (PSCo)	$ 0.30	$ 0.33	$ 0.72	$ 0.77
NSP-Minnesota	0.27	0.31	0.63	0.67
Southwestern Public Service Company (SPS)	0.13	0.11	0.23	0.19
NSP-Wisconsin	0.04	0.05	0.11	0.11
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility	0.75	0.81	1.72	1.77
Xcel Energy Inc. and other	(0.02)	(0.04)	(0.08)	(0.12)
Ongoing [(a)] diluted EPS	0.73	0.77	1.64	1.65
SPS 2004 FERC complaint case orders [(b)]	—	(0.04)	—	(0.04)
GAAP diluted EPS	**$ 0.73**	**$ 0.73**	**$ 1.64**	**$ 1.61**

(a) See Note 2.
(b) See Note 7.

PSCo — PSCo's ongoing earnings decreased $0.03 per share for the third quarter and $0.05 per share for the nine months ended Sept. 30, 2014. Increases in electric and natural gas rates, higher allowance for funds used during construction (AFUDC), weather-normalized sales growth and lower operating and maintenance (O&M) expenses were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings decreased $0.04 per share for the third quarter and nine months ended Sept. 30, 2014. Electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth were more than offset by the impact of unfavorable weather, lower AFUDC and increases in O&M expenses, property taxes and interest charges.

SPS — SPS' ongoing earnings increased $0.02 per share for the third quarter and $0.04 per share for the nine months ended Sept. 30, 2014, primarily due to higher electric rates in New Mexico and Texas and weather-normalized sales growth, partially offset by higher depreciation, O&M expenses and interest charges.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings decreased $0.01 per share for the third quarter of 2014 and were flat year-to-date. Higher electric and natural gas margins, due to an electric rate increase and weather-normalized sales growth were offset by higher O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by $0.02 per share for the third quarter and $0.04 for the nine months ended Sept. 30, 2014, largely due to lower financing costs as a result of refinancing junior subordinated notes with lower cost debt.

The following table summarizes significant components contributing to the changes in 2014 EPS compared with the same period in 2013, which are discussed in more detail later in the release:

Diluted Earnings (Loss) Per Share [a]	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2013 GAAP diluted EPS	**$ 0.73**	**$ 1.61**
SPS 2004 FERC complaint case orders [b]	0.04	0.04
2013 ongoing diluted EPS	**0.77**	**1.65**
Components of change — 2014 vs. 2013		
Higher electric margins	0.01	0.15
Higher natural gas margins	0.01	0.05
Lower interest charges	—	0.01
Higher AFUDC — equity	—	0.01
Lower (higher) O&M expenses	0.01	(0.06)
Higher taxes (other than income taxes)	(0.02)	(0.05)
Higher depreciation and amortization	(0.03)	(0.04)
Higher conservation and demand side management (DSM) program expenses	(0.01)	(0.04)
Dilution from equity issued through the at-the-market (ATM) program, direct stock purchase plan and benefit plans	(0.01)	(0.02)
Other, net	—	(0.02)
2014 GAAP and ongoing diluted EPS	**$ 0.73**	**$ 1.64**

[a] See Note 2.
[b] See Note 7.

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 Sept. 30			Nine Months Ended Sept. 30		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
HDD	(11.2)%	(46.2)%	60.9%	11.5%	5.4%	4.7%
CDD	(4.0)	15.6	(16.7)	(2.5)	25.3	(20.6)
THI	(17.3)	28.0	(32.2)	(11.2)	23.0	(24.3)

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		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
Retail electric	$ (0.024)	$ 0.048	$ (0.072)	$ 0.010	$ 0.079	$ (0.069)
Firm natural gas	—	(0.001)	0.001	0.018	0.015	0.003
Total	$ (0.024)	$ 0.047	$ (0.071)	$ 0.028	$ 0.094	$ (0.066)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2014:

	Three Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(7.4)%	(10.5)%	(6.2)%	(5.2)%	(9.1)%
Electric commercial and industrial	(0.8)	2.6	0.1	(0.2)	(2.4)
Total retail electric sales	(2.7)	(1.2)	(1.4)	(1.8)	(4.5)
Firm natural gas sales	5.7	(1.6)	N/A	6.2	6.6

	Three Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	(0.4)%	(0.4)%	(2.8)%	(0.5)%	0.6%
Electric commercial and industrial	1.5	5.1	0.8	2.5	0.6
Total retail electric sales	0.9	3.5	—	1.5	0.5
Firm natural gas sales	3.6	(4.5)	N/A	4.8	3.1

	Nine Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(1.7)%	—%	(0.1)%	(3.1)%	(1.5)%
Electric commercial and industrial	0.8	4.4	2.4	(0.1)	(0.1)
Total retail electric sales	0.1	3.1	1.8	(1.0)	(0.6)
Firm natural gas sales	3.9	12.1	N/A	(1.1)	12.2

	Nine Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.6%	0.3%	0.1%	0.5%	1.0%
Electric commercial and industrial	1.7	4.6	2.9	1.6	0.6
Total retail electric sales	1.4	3.3	2.3	1.3	0.7
Firm natural gas sales	4.8	3.6	N/A	5.6	3.7

Weather-normalized Electric Growth (Decline)

- NSP-Wisconsin's year-to-date electric sales growth was largely due to strong sales to large commercial and industrial (C&I) customers primarily in the oil, gas and sand mining industries.
- SPS' year-to-date C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area. The third quarter decline of SPS residential sales was attributed to the refinement of the estimation process as a result of the recently launched Southwest Power Pool, Inc. (SPP) market and lower use per customer.
- PSCo's year-to-date electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota's year-to-date electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas Growth

- Across our natural gas service territories, strong sales were experienced year-to-date, which continued the trend that began in the last half of 2013. As normal weather conditions are typically defined as a 30-year average of actual weather conditions, significant weather fluctuations in periods of low demand may result in large percentage changes on small volumes. Extreme weather variations and factors such as windchill and cloud cover may not be fully reflected.

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 Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	**2014**	**2013**	**2014**	**2013**
Electric revenues	$ 2,616	$ 2,600	$ 7,216	$ 6,912
Electric fuel and purchased power	(1,080)	(1,098)	(3,188)	(3,034)
Electric margin	$ 1,536	$ 1,502	$ 4,028	$ 3,878

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

(Millions of Dollars)	**Three Months Ended Sept. 30 2014 vs. 2013**	**Nine Months Ended Sept. 30 2014 vs. 2013**
Retail rate increases [(a)]	$ 39	$ 93
Non-fuel riders	13	37
Conservation and DSM program revenues (offset by expenses)	8	33
Transmission revenue, net of costs	3	25
Retail sales growth, excluding weather impact	3	22
Estimated impact of weather	(56)	(53)
Firm wholesale	7	(7)
Other, net	(9)	(26)
Total increase in ongoing electric margin	8	124
SPS 2004 FERC complaint case orders [(b)]	26	26
Total increase in electric margin	$ 34	$ 150

(a) The retail rate increases include final rates in Minnesota (2013), Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota (2014), subject to and net of estimated provision for refund. See Note 4 for further discussion.

(b) As a result of two orders issued by the Federal Energy Regulatory Commission (FERC), a pretax charge of approximately $35 million ($31 million in electric revenues, of which $5 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in the third quarter of 2013. See Note 5.

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 to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect 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)	**2014**	**2013**	**2014**	**2013**
Natural gas revenues	$ 237	$ 205	$ 1,485	$ 1,216
Cost of natural gas sold and transported	(99)	(75)	(934)	(703)
Natural gas margin	$ 138	$ 130	$ 551	$ 513

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

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Retail rate increase, net of refund (Colorado)	$ (1)	$ 16
Pipeline system integrity adjustment rider (Colorado), partially offset in O&M expenses	7	10
Retail sales growth	1	7
Estimated impact of weather	—	3
Other, net	1	2
Total increase in natural gas margin	$ 8	$ 38

O&M Expenses — O&M expenses decreased $6.9 million, or 1.2 percent, for the third quarter of 2014 and increased $47.0 million, or 2.8 percent, for the nine months ended Sept. 30, 2014. The year-to-date increase in O&M expense is partially due to the timing of a prior year nuclear outage (i.e., amortization of the Monticello outage began in July 2013).

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Nuclear plant operations and amortization	$ (1)	$ 25
Electric and natural gas distribution expenses	(1)	12
Plant generation costs	2	8
Transmission costs	1	7
Employee benefits	(9)	(18)
Other, net	1	13
Total (decrease) increase in O&M expenses	$ (7)	$ 47

For the third quarter of 2014, O&M expenses (decreased) increased due to the following:

- Nuclear plant operations and amortization expense reductions were driven by lower plant operations spending. The expense for 2013 included one-time contractor and consulting expense for various projects and initiatives to improve the operational efficiencies of the plants.
- Electric and natural gas distribution expense declines were primarily driven by the timing of pipeline system integrity projects;
- Plant generation costs were driven by the timing of overhauls and purchases of chemicals;
- Transmission costs increased as a result of higher substation maintenance and repairs; and
- Lower employee benefits resulted primarily from decreases in pension expense, retiree medical costs and annual employee incentive accruals.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $7.4 million, or 10.9 percent, for the third quarter of 2014 and $31.3 million, or 16.3 percent, for the nine months ended Sept. 30, 2014. These increases were primarily attributable to higher electric recovery rates at NSP-Minnesota and PSCo.

Depreciation and Amortization — Depreciation and amortization increased $26.9 million, or 11.8 percent, for the third quarter of 2014 and $35.5 million, or 4.9 percent, year-to-date. The increases were primarily attributed to normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets. See further discussion within Note 4.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $12.7 million, or 12.0 percent, for the third quarter of 2014 and $38.2 million, or 11.9 percent, for the nine months ended Sept. 30, 2014. The increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC increased $2.6 million for the third quarter of 2014 and $6.9 million year-to-date. The increases were due to construction primarily related to the Clean Air Clean Jobs Act (CACJA) projects and the expansion of transmission facilities, partially offset by the reduction caused by the portion of the Monticello life cycle management (LCM)/ extended power uprate (EPU) placed in service in July 2013.

Interest Charges — Interest charges decreased $1.3 million, or 0.9 percent, for the third quarter of 2014 and $9.3 million, or 2.2 percent, for the nine months ended Sept. 30, 2014. The decreases were primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels in the current period. In addition, in 2013 interest charges were incurred for customer refunds at SPS and NSP-Minnesota and a $6.3 million write off of unamortized debt expense associated with the calling of junior subordinated notes in May 2013.

***Income Taxes* —** Income tax expense increased $2.6 million for the third quarter of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, decreased permanent plant-related adjustments in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by a tax benefit for prior year adjustments in 2014. The effective tax rate (ETR) was 34.7 percent for the third quarter of 2014, compared to 34.6 percent for the third quarter of 2013.

Income tax expense increased $25.3 million for the first nine months of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, decreased permanent plant-related adjustments in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by the successful resolution of a 2010-2011 Internal Revenue Service audit issue in 2014 and a tax benefit for prior year adjustments in 2014. The ETR was 34.6 percent for the first nine months of 2014, compared to 34.0 percent for the first nine months of 2013 due to these adjustments.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)		Sept. 30, 2014	Percentage of Total Capitalization
Current portion of long-term debt	$	0.2	1%
Short-term debt		0.7	3
Long-term debt		11.5	51
Total debt		12.4	55
Common equity		10.2	45
Total capitalization	$	22.6	100%

Credit Facilities — As of Oct. 27, 2014, 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.	$	1,000.0	$	360.0	$	640.0	$	0.3	$	640.3
PSCo		700.0		334.5		365.5		0.8		366.3
NSP-Minnesota		500.0		114.9		385.1		1.1		386.2
SPS		400.0		66.0		334.0		0.4		334.4
NSP-Wisconsin		150.0		32.0		118.0		0.9		118.9
Total	$	2,750.0	$	907.4	$	1,842.6	$	3.5	$	1,846.1

(a) These credit facilities have been amended to expire in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

***Amended Credit Agreements* —** On Oct. 14, 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an extension of maturity from July 2017 to October 2019. In addition, the borrowing limit for Xcel Energy Inc. has been increased to $1 billion from $800 million and the borrowing limit for SPS has been increased to $400 million from $300 million. As a result, the total borrowing limit under the amended credit agreements increased to $2.75 billion from $2.45 billion.

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 Oct. 27, 2014, 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 current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2014 through 2019 are shown in the table below.

	Forecast						
(Millions of Dollars)	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
By Subsidiary							
NSP-Minnesota	$ 1,130	$ 1,625	$ 990	$ 975	$ 845	$ 950	$ 5,385
PSCo	1,055	950	820	815	885	1,010	4,480
SPS	535	570	710	735	595	565	3,175
NSP-Wisconsin	280	230	260	300	325	325	1,440
Total capital expenditures	$ 3,000	$ 3,375	$ 2,780	$ 2,825	$ 2,650	$ 2,850	$ 14,480

By Function	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
Electric transmission	$ 985	$ 875	$ 780	$ 905	$ 975	$ 1,000	$ 4,535
Electric generation	715	1,190	630	620	415	450	3,305
Electric distribution	560	605	630	640	650	680	3,205
Natural gas	380	370	370	305	355	380	1,780
Nuclear fuel	130	90	120	120	65	150	545
Other	230	245	250	235	190	190	1,110
Total capital expenditures	$ 3,000	$ 3,375	$ 2,780	$ 2,825	$ 2,650	$ 2,850	$ 14,480

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 (TransCos).

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. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2019 are shown in the table below.

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from Operations*	$	11,500
New Debt**		2,605
Equity from Dividend Reinvestment Program (DRIP) and Benefit Programs		375
2015-2019 Capital Expenditures	$	14,480
Maturing Debt	$	2,995

* Cash from operations, net of dividend and pension funding.
** Reflects a combination of short and long-term debt.

During 2015, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $500 million of senior unsecured bonds;
- PSCo plans to issue approximately $400 million of first mortgage bonds;
- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- SPS plans to issue approximately $250 million of first mortgage bonds; and
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds.

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

2014 Financing Activity — During 2014, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044;
- In May, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June, NSP-Wisconsin issued $100 million of 3.30 percent first mortgage bonds due June 15, 2024.

Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an ATM program for approximately $175 million during the first six months of 2014. As a result, Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity, beyond its DRIP and benefit programs, over the next five years based on its current capital expenditure plan.

Note 4. Rates and Regulation

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the Minnesota Public Utilities Commission (MPUC). The rate case is based on a requested return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015.

The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million or 6.9 percent in 2014 and an additional $98 million or 3.5 percent in 2015. The request includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, NSP-Minnesota requested a rate increase of $127 million or 4.6 percent in 2014 and an incremental rate increase of $164 million or 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve and the use of expected funds from the U.S. Department of Energy (DOE) for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello LCM/EPU project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island (PI) EPU project.

In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota's request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

In August 2014, the evidentiary hearing was completed. As a result of discussions between NSP-Minnesota and intervening parties, the outstanding issues were further narrowed and the following were agreed upon:

- NSP-Minnesota and the Minnesota Department of Commerce (DOC) have agreed to true-up the sales forecast to 12 months of actual weather normalized sales for 2014.
- NSP-Minnesota and the DOC agreed to a property tax adjustment of $9 million, based on an assumed 2014 property tax forecast of $141 million. The parties also agreed to a limited true-up mechanism in which NSP-Minnesota would recover actual 2014 property taxes up to $145 million.
- NSP-Minnesota agreed with the Minnesota Chamber of Commerce recommendation regarding deferral of the 2014 Monticello EPU depreciation expense and amortization of the depreciation over the remaining life of the plant.

NSP-Minnesota revised its requested rate increase to $142.2 million for 2014 and to $106.0 million for 2015, for a total combined increase of $248.2 million.

The following table summarizes the DOC's and NSP-Minnesota's recommendations and includes the estimated impact of certain agreed-upon true-up adjustments:

2014 Rate Request (Millions of Dollars)	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$ 192.7	$ 192.7
Sales forecast	(43.2)	(15.8)
ROE	(36.2)	—
Monticello EPU cost recovery	(33.9)	—
Monticello EPU depreciation deferral	—	(12.2)
Property taxes	(9.0)	(9.0)
PI EPU	(5.1)	(5.1)
Health care, pension and other benefits	(11.4)	(1.9)
Other, net	(8.0)	(6.5)
Total recommendation 2014 — unadjusted	$ 45.9	$ 142.2
Estimated true-up adjustments:		
Sales forecast	$ 18.3	$ (9.1)
Property taxes	3.9	3.9
Total recommendation 2014 — adjusted	$ 68.1	$ 137.0

2015 Rate Request (Millions of Dollars)	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$ 98.5	$ 98.5
Monticello EPU cost recovery	29.1	—
Monticello EPU cost disallowance [(a)]	(10.2)	—
Excess depreciation reserve adjustment [(b)]	(22.7)	—
Depreciation	(17.5)	—
Monticello EPU depreciation deferral	—	1.6
Monticello EPU step increase	—	10.1
Property taxes	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)
DOE settlement proceeds	10.1	10.1
Emission chemicals	(1.6)	(1.6)
Other, net	(4.8)	1.7
Total recommendation 2015 step increase	$ 66.5	$ 106.0
Unadjusted cumulative total for 2014 and 2015 step increase	$ 112.4	$ 248.2
Estimated adjusted cumulative total for 2014 and 2015 step increase	$ 134.6	$ 243.0

(a) In July 2014, the DOC recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis. This equates to a total NSP System, which includes NSP-Minnesota and NSP-Wisconsin, disallowance of approximately $94 million. This would reduce NSP-Minnesota's revenue requirement by approximately $10.2 million in 2015.

(b) Adjustment is due to timing differences and/or methodology of accelerating amortization of the excess depreciation reserve over three years.

NSP-Minnesota's revised rate request, moderation plan, interim rate adjustments and impacts on expenses are detailed below:

(Millions of Dollars)	2014	Percentage Increase	2015	Percentage Increase
Rebuttal pre-moderation deficiency	$ 250.6		$ 67.8	
Evidentiary hearing adjustments	(27.3)		11.0	
Revised pre-moderation deficiency	223.3		78.8	
Moderation plan:				
Excess depreciation reserve	(81.1)		52.9	
DOE settlement proceeds	—		(25.7)	
Revised rate request	142.2	5.1%	106.0	3.8%
Interim rate adjustments	(65.3)		65.3	
PI EPU	4.8		(4.8)	
Revenue impact [(a)]	81.7		166.5	
Excess depreciation reserve	81.1		(45.7)	
Sales forecast [(b)]	(9.1)		—	
DOE settlement proceeds	—		25.7	
Estimated impact of request on operating income	$ 153.7		$ 146.5	

(a) NSP-Minnesota's total revenue for 2014 is capped at the interim rate level of $127 million and pre-tax operating income is capped at $208 million. This table demonstrates the impact of reducing NSP-Minnesota's rebuttal request.

(b) NSP-Minnesota and the DOC have agreed to a sales true-up based on weather normalized sales for 2014, using standard weather coefficients. NSP-Minnesota periodically adjusts the coefficients in periods of extreme weather conditions to enhance weather impact estimates. As a result of the difference in the two methodologies, currently, approximately $9.1 million of revenue that NSP-Minnesota attributed to weather would be considered normal sales growth using the standard weather coefficients. The refund for the full year could vary from the estimate as of Sept. 30, 2014, depending on weather conditions.

NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with interim rates as of Sept. 30, 2014.

The next step in the procedural schedule is expected to be the Administrative Law Judge (ALJ) Report on Dec. 26, 2014. The MPUC is expected to deliberate on March 26, 2015. A final MPUC order is anticipated in the second quarter of 2015.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW). Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes AFUDC. Project expenditures were initially estimated at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

NSP-Minnesota filed a report to support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional Nuclear Regulatory Commission (NRC) licensing related requests over the five-plus year application process.

The cost deviation is in line with similar nuclear upgrade projects undertaken by other utilities. In addition, the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and has begun the process to comply with the license requirements for higher power levels, subject to NRC oversight and review.

In July 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis. This equates to a total NSP System, which includes NSP-Minnesota and NSP-Wisconsin, disallowance of approximately $94 million.

The DOC's recommendation indicated that although the combined LCM/EPU project is cost effective, NSP-Minnesota should have done a better job of estimating initial project costs of the investments required to achieve 71 MW of additional capacity (i.e., EPU costs) as opposed to investments required to extend the life of the plant. They asserted that approximately 85 percent of the total $665 million in costs were associated with project components required solely to achieve the EPU.

In August 2014, the Office of Attorney General (OAG) filed rebuttal testimony and recommended a disallowance of recovery of $321 million for the entire NSP System (based on a total capitalized cost of $748 million), and no return on $107 million. The recommended disallowance is primarily based on criticism of NSP-Minnesota's management of the project.

NSP-Minnesota believes the costs of the project were prudent and its decisions and actions do not warrant a disallowance. NSP-Minnesota's testimony is summarized as follows:

- The plant is cost-effective for customers;
- The project benefits include providing carbon-free generation through a life extension and uprate of the plant for an installed capacity of about $1,000 per kilowatt;
- The DOC was incorrect in its analysis that 85 percent of the expenditures were associated with the uprate; and
- NSP-Minnesota made prudent decisions based on the information available at the time the decisions were made.

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

- Initial Briefs — Oct. 31, 2014;
- Reply Briefs — Nov. 21, 2014;
- ALJ Report — Dec. 31, 2014; and
- MPUC Deliberation — March 6, 2015.

A final MPUC order is anticipated in the second quarter of 2015. The MPUC decision for the Monticello prudence review is expected to be reflected in the final results of NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's Resource Plan and ordered a competitive acquisition process with the goal of adding approximately 500 MW of generation to the NSP System by 2019.

In May 2014, the MPUC issued its order directing NSP-Minnesota to negotiate a 100 MW solar purchased power agreement (PPA) with Geronimo Energy, a natural gas, combined-cycle PPA with Calpine, and a natural gas, combustion turbine PPA with Invenergy. The MPUC also directed NSP-Minnesota to present its final pricing terms for its 215 MW natural gas combustion turbine, self-build option at the Black Dog site.

In September 2014, NSP-Minnesota filed an updated assessment of generating resource needs which indicates that it will have surplus generating capacity through at least 2019. NSP-Minnesota requested to postpone negotiations of the thermal PPAs until spring 2015. NSP-Minnesota also expressed reservations about the significant price differences in the solar options resulting from solar request for proposals (RFP). NSP-Minnesota suggested the MPUC consolidate its determinations regarding the amount of solar to be added to the NSP System, as well as the specific mix of PPAs that will be best for NSP-Minnesota's customers.

In October 2014, NSP-Minnesota filed a petition with the MPUC seeking approval of two or three solar PPAs, depending on the MPUC's determination regarding the Geronimo Energy solar PPA. The MPUC is anticipated to act on NSP-Minnesota's recommendations in December 2014.

NSP-Minnesota's next Resource Plan is expected to be filed with the MPUC in January 2015.

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In August 2014, NSP-Minnesota filed a GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessment and system upgrades in 2015 and beyond, as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota is requesting recovery of approximately $14.9 million from Minnesota gas utility customers beginning Jan. 1, 2015, including $4.8 million of deferred sewer separation and integrity management costs which is the 2015 portion of a five year amortization. In October 2014, the DOC recommended approval of NSP-Minnesota's request for recovery of the GUIC rider, using the capital structure and cost of capital proposed in the current electric case and a five year amortization period for the deferred costs. An MPUC decision is anticipated by the end of 2014.

***NSP-Minnesota – South Dakota 2015 Electric Rate Case* —** In June 2014, NSP-Minnesota filed a request with the South Dakota Public Utilities Commission (SDPUC) to increase South Dakota electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 historic test year adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of $433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately $9.0 million for certain Transmission Cost Recovery (TCR) rider and Infrastructure rider projects to base rates.

The major components of the request are as follows:

(Millions of Dollars)	Request
Nuclear investments and operating costs	$ 13.4
Other production, transmission and distribution	5.0
Technology improvements	2.1
Pension and O&M	1.6
Wind generation facilities	1.4
Capital structure	1.1
Incremental increase to base rates	$ 24.6
Infrastructure rider to be included in base rates	$ (8.4)
TCR rider to be included in base rates	(0.6)
Net request	$ 15.6

At this time, the case is in the discovery phase and further procedure scheduling may be established during the fourth quarter of 2014. In November 2014, NSP-Minnesota plans to file a request with the SDPUC for interim rates, effective Jan. 1, 2015. Final rates are anticipated to be effective in the first quarter of 2015.

***NSP-Wisconsin – Wisconsin 2015 Electric Rate Case* —** In May 2014, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase electric rates by $20.6 million, or 3.2 percent, effective Jan. 1, 2015. The request is for the limited purpose of updating 2015 electric rates to reflect anticipated increases in the production and transmission fixed charges and the fuel and purchased power components of the interchange agreement with NSP-Minnesota. No changes are being requested to the capital structure or the 10.2 percent ROE authorized by the PSCW in the 2014 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 for 2015 only, in which 100 percent of the earnings above the authorized ROE would be refunded to customers.

In October 2014, the PSCW Staff filed their direct testimony and recommended an electric rate increase of $16.1 million, or 2.5 percent. The majority of the PSCW Staff's adjustments are related to the fuel cost forecast, and are primarily the result of more recent data than was available at the time the initial filing was prepared last spring.

In October 2014, NSP-Wisconsin, the PSCW Staff and other parties reached an agreement that resolved all contested issues in the case and accepted the PSCW staff recommendation to increase NSP-Wisconsin's electric rates by approximately $16.1 million, effective January 2015.

The major cost components of the requested increase and the PSCW Staff recommendation are summarized below:

(Millions of Dollars)	**NSP-Wisconsin Request**	**PSCW Staff Recommendation**
Production and transmission fixed charges	$ 28.1	$ 26.4
Fuel and purchased power	13.9	11.1
Sub-Total	$ 42.0	$ 37.5
NSP-Minnesota transmission depreciation reserve	$ (16.2)	$ (16.2)
Monticello EPU deferral	(5.2)	(5.2)
Total	$ 20.6	$ 16.1

A final PSCW decision is anticipated by the end of 2014.

PSCo – Colorado 2014 Electric Rate Case — In 2014, PSCo filed an electric rate case with the Colorado Public Utilities Commission (CPUC) requesting an increase in annual revenue of approximately $136.0 million, or 4.83 percent. The requested 2015 rate increase reflects approximately $100.9 million for recovery of costs associated with the CACJA project. The case also requests the initiation of a CACJA rider for 2016 and 2017, which is anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017. PSCo's objective is to establish a multi-year regulatory plan that provides certainty for PSCo and its customers.

The rate filing is based on a 2015 test year, a requested ROE of 10.35 percent, an electric rate base of $6.39 billion and an equity ratio of 56 percent. As part of the filing, PSCo will transfer approximately $19.9 million from the transmission rider to base rates, which will not impact customer bills. The CACJA rider is projected to recover incremental investment and expenses, based on a comprehensive plan to retire certain coal plants, add pollution control equipment to other existing coal units and add natural gas generation. The CACJA project investment is expected to be completed by 2017.

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

- Answer Testimony — Nov. 7, 2014;
- Rebuttal Testimony — Dec. 17, 2014;
- Evidentiary Hearing — Jan. 26 - Feb. 4, 2015;
- Interim rates are scheduled to be effective on Feb. 13, 2015, subject to refund; and
- A decision as well as implementation of final rates are anticipated in the second quarter of 2015.

PSCo – Annual Electric Earnings Test — As part of an annual earnings test, PSCo must share with customers a portion of any annual earnings that exceed PSCo's authorized ROE threshold of 10 percent for 2012-2014. In April 2014, PSCo filed its 2013 earnings test with the CPUC proposing a refund obligation of $45.7 million to electric customers to be returned between August 2014 and July 2015. This tariff was approved by the CPUC in July 2014 and became effective Aug. 1, 2014. As of Sept. 30, 2014, PSCo has also recognized management's best estimate of an accrual for the 2014 earnings test of $52.4 million.

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas with each of its Texas municipalities and the Public Utility Commission of Texas (PUCT) for a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflected a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the Transmission Cost Recovery Factor (TCRF) to zero when the final base rates become effective. In April 2014, SPS revised its request to a net increase of $48.1 million.

The rate filing was based on a historic test year ending June 2013, a requested ROE of 10.40 percent, an electric rate base of approximately $1.27 billion and an equity ratio of 53.89 percent. The requested rate increase reflected an increase in depreciation expense of approximately $16 million.

In September 2014, SPS, PUCT staff, and intervenors filed a non-unanimous settlement agreement, subject to PUCT approval, which would increase SPS' rates by $37 million, or 3.5 percent, retroactive to June 1, 2014. Starting Oct. 1, 2014, SPS began collecting the rate increase through interim rates subject to refund. SPS expects to recover the rate increase for the months of June through September through a separate surcharge to be implemented by the first quarter of 2015. Based on the anticipated outcome of the rate case, SPS recognized approximately $13.3 million of revenue in the third quarter of 2014 for the surcharge. The PUCT is expected to rule on the settlement in 2014.

TransCos — In 2014, Xcel Energy formed the Xcel Energy Transmission Holding Company, LLC and two second-tier transmission subsidiaries that will participate in the Midcontinent Independent System Operator, Inc. (MISO) and SPP competitive bidding processes as a qualified transmission developer (QTD) and qualified RFP participant (QRP), respectively. Transmission assets held by these entities will be subject to FERC jurisdiction.

Xcel Energy Transmission Development Company, LLC (XETD) was approved as a non-transmission owning member in MISO in April 2014, and a QTD in September 2014. This allows XETD to competitively bid for MISO transmission projects starting in 2015 or 2016.

Xcel Energy Southwest Transmission Company, LLC (XEST) filed a QRP application in June 2014, which SPP found complete in September 2014. This allows XEST to competitively bid for SPP transmission projects starting in 2015.

In August 2014, XETD and XEST filed forward-looking transmission formula rates with the FERC that will apply in their respective jurisdictions with a requested effective date of Nov. 1, 2014. The TransCo rate filings are pending action by the FERC, which is expected by the end of 2014.

- Both TransCos requested a capital structure based on 55 percent equity and 45 percent debt.
- XETD requested a base ROE using the currently applicable MISO regional rate of 12.38 percent, subject to any potential modifications resulting from a pending ROE complaint against MISO and the MISO transmission owners.
- XEST requested a base ROE of 10.64 percent, plus a 50 basis point adder for membership in SPP. Certain parties protested or commented on the formula rate filings, and XEST and XETD filed answers on Oct. 6, 2014.

Note 5. SPS FERC Orders

In August 2013, the FERC issued an order on rehearing related to a 2004 complaint case brought by Golden Spread Electric Cooperative, Inc. (Golden Spread), a wholesale cooperative customer, and Public Service Company of New Mexico (PNM) and an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaint included two key components: 1) PNM's claim regarding inappropriate allocation of fuel costs and 2) a base rate complaint, including the appropriate demand-related cost allocator. The FERC previously determined that the allocation of fuel costs and the demand-related cost allocator utilized by SPS was appropriate.

In the August 2013 Orders, the FERC clarified its previous ruling on the allocation of fuel costs and reaffirmed that the refunds in question should only apply to firm requirements customers and not PNM's contractual load. The FERC also reversed its prior demand-related cost allocator decision. The FERC stated that it had erred in its initial analysis and concluded that the SPS system was a 3 coincident peak (CP) rather than a 12CP system.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling.

In October 2013, the FERC issued orders further considering the requests for rehearing. These matters are currently pending the FERC's action. If unsuccessful in its rehearing request, SPS will have the opportunity to file rate cases with the FERC and its retail jurisdictions seeking to change all customers to a 3CP allocation method.

As of Dec. 31, 2013, SPS had accrued $44.5 million related to the August 2013 Orders and an additional $4.0 million of principal and interest was accrued during the first nine months of 2014. Pending the timing and resolution of this matter, the annual impact to revenues through 2014 could be up to $6 million and decreasing to $4 million on June 1, 2015.

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

Xcel Energy Earnings Guidance — Xcel Energy anticipates that 2014 ongoing earnings will be within the guidance range of $1.95 to $2.05 per share. This is compared with the previously stated guidance range of $1.90 to $2.05 per share. Key assumptions related to 2014 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 increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to increase approximately 3.0 percent.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $30 million to $40 million over 2013 levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $40 million to $50 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $5 million to $15 million from 2013 levels.
- AFUDC — equity is projected to increase up to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 504 million shares.

Xcel Energy's 2015 ongoing guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 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 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2.0 percent.
- Capital rider revenue is projected to increase by $65 million to $75 million over 2014 projected levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 projected levels.
- Depreciation expense is projected to increase $160 million to $180 million over 2014 projected levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $30 million in 2015.
- Property taxes are projected to increase approximately $75 million to $85 million over 2014 projected levels. The increase reflects that incremental property taxes in Colorado are no longer being deferred and also the amortization of previously deferred property taxes.
- Interest expense (net of AFUDC — debt) is projected to increase $65 million to $75 million over 2014 projected levels.
- AFUDC — equity is projected to decline approximately $30 million to $40 million from 2014 projected levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 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 a normalized 2013 EPS of $1.90 per share, which represented the mid-point of our 2013 earnings guidance range;
- Deliver annual dividend increases of 4 percent to 6 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 7. 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 Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	**2014**	**2013**	**2014**	**2013**
Ongoing earnings	$ 368,582	$ 384,272	$ 824,967	$ 817,699
SPS 2004 FERC complaint case orders	—	(19,520)	—	(19,520)
GAAP earnings	$ 368,582	$ 364,752	$ 824,967	$ 798,179

SPS FERC Orders — As a result of the two orders issued in August 2013 by the FERC for a potential SPS customer refund, a pre-tax charge of $35 million was recorded in the third quarter of 2013. Of this amount, approximately $30 million ($26 million revenue reduction and $4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, GAAP earnings include the total after tax amount of $22.5 million and ongoing earnings exclude $19.5 million. See Note 5.

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

	Three Months Ended Sept. 30	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 2,853,000	$ 2,805,283
Other	16,807	17,055
Total operating revenues	2,869,807	2,822,338
Net income	$ 368,582	$ 364,752
Weighted average diluted common shares outstanding	506,365	498,641
Components of EPS — Diluted [a]		
Regulated utility	$ 0.75	$ 0.81
Xcel Energy Inc. and other costs	(0.02)	(0.04)
Ongoing diluted EPS	**0.73**	**0.77**
SPS 2004 FERC complaint case orders [b]	—	(0.04)
GAAP diluted EPS	**$ 0.73**	**$ 0.73**

	Nine Months Ended Sept. 30	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 8,701,163	$ 8,128,273
Other	56,344	55,827
Total operating revenues	8,757,507	8,184,100
Net income	$ 824,967	$ 798,179
Weighted average diluted common shares outstanding	503,213	495,767
Components of EPS — Diluted [a]		
Regulated utility	$ 1.72	$ 1.77
Xcel Energy Inc. and other costs	(0.08)	(0.12)
Ongoing diluted EPS	**1.64**	**1.65**
SPS 2004 FERC complaint case orders [b]	—	(0.04)
GAAP diluted EPS	**$ 1.64**	**$ 1.61**
Book value per share	$ 20.09	$ 19.19

(a) See Note 2.
(b) See Note 7.