414 Nicollet Mall
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Jan. 31, 2013

XCEL ENERGY
2012 YEAR END EARNINGS REPORT

- Ongoing 2012 earnings per share were $1.82 compared with $1.72 per share in 2011.
- GAAP (generally accepted accounting principles) 2012 earnings per share were $1.85 compared with $1.72 per share in 2011.
- Xcel Energy reaffirms 2013 earnings guidance of $1.85 to $1.95 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2012 GAAP earnings of $905 million, or $1.85 per share compared with 2011 GAAP earnings of $841 million, or $1.72 per share.

Ongoing earnings, which exclude one adjustment, were $1.82 per share for 2012 compared with $1.72 per share in 2011. Ongoing earnings increased largely due to increases in electric margins driven by the conclusion of various rate cases, which reflect our continued investment in our utility business and a lower effective tax rate. Partially offsetting these positive factors were warmer than normal winter weather, increases in depreciation expense, operating and maintenance expenses and property taxes.

“We had an excellent year financially and operationally in 2012,” said Ben Fowke, Chairman, President and Chief Executive Officer. “We delivered earnings in the upper half of our guidance range, which represents the eighth consecutive year in which we have met or exceeded our earnings guidance and for the ninth consecutive year we increased our dividend. We implemented a multi-year rate plan in Colorado and reached constructive regulatory outcomes in several other rate cases. Finally, we maintained excellent reliability during one of the warmest years on record, all executed with outstanding safety performance.”

“We have established a solid strategy and continue to execute our business plan. As a result, we are well positioned to deliver on our 2013 earnings guidance of $1.85 to $1.95 per share,” stated Fowke.

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings Per Share	**2012**	**2011**	**2012**	**2011**
Ongoing[(a)] diluted earnings per share	$ **0.29**	$ **0.29**	$ **1.82**	$ **1.72**
Prescription drug tax benefit [(a)]	-	-	0.03	-
GAAP diluted earnings per share	$ **0.29**	$ **0.29**	$ **1.85**	$ **1.72**

(a) See Note 6.

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:	(877) 941-0844
International Dial-In:	(480) 629-9835
Conference ID:	4577479

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 2:00 p.m. CST on Jan. 31 through 11:59 p.m. CST on Feb. 1.

Replay Numbers	
US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4577479 #

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 2013 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; 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, 2011 and Quarterly Reports on Form 10-Q for the quarters ended March 31, June 30 and Sept. 30, 2012.

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Xcel Energy internet address: www.xcelenergy.com

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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	
	2012	2011	2012	2011
Operating revenues				
Electric	$ 2,010,976	$ 1,988,800	$ 8,517,296	$ 8,766,593
Natural gas	520,513	560,109	1,537,374	1,811,926
Other	19,646	19,501	73,553	76,251
Total operating revenues	2,551,135	2,568,410	10,128,223	10,654,770
Operating expenses				
Electric fuel and purchased power	898,752	920,293	3,623,935	3,991,786
Cost of natural gas sold and transported	323,495	370,351	880,939	1,163,890
Cost of sales — other	8,568	8,291	29,067	30,391
Operating and maintenance expenses	599,917	565,130	2,176,095	2,140,289
Conservation and demand side management program expenses	69,285	69,303	260,527	281,378
Depreciation and amortization	231,689	194,303	926,053	890,619
Taxes (other than income taxes)	103,032	96,738	408,924	374,815
Total operating expenses	2,234,738	2,224,409	8,305,540	8,873,168
Operating income	316,397	344,001	1,822,683	1,781,602
Other income, net	1,222	960	6,175	9,255
Equity earnings of unconsolidated subsidiaries	7,821	7,714	29,971	30,527
Allowance for funds used during construction — equity	18,336	12,533	62,840	51,223
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,961, $6,295, $24,087 and $24,019, respectively	144,112	152,395	601,582	591,098
Allowance for funds used during construction — debt	(10,586)	(6,606)	(35,315)	(28,181)
Total interest charges and financing costs	133,526	145,789	566,267	562,917
Income from continuing operations before income taxes	210,250	219,419	1,355,402	1,309,690
Income taxes	70,042	78,478	450,203	468,316
Income from continuing operations	140,208	140,941	905,199	841,374
(Loss) income from discontinued operations, net of tax	(38)	(432)	30	(202)
Net income	140,170	140,509	905,229	841,172
Dividend requirements on preferred stock	-	-	-	3,534
Premium on redemption of preferred stock	-	-	-	3,260
Earnings available to common shareholders	$ 140,170	$ 140,509	$ 905,229	$ 834,378
Weighted average common shares outstanding:				
Basic	488,428	486,223	487,899	485,039
Diluted	489,136	486,991	488,434	485,615
Earnings per average common share:				
Basic	$ 0.29	$ 0.29	$ 1.86	$ 1.72
Diluted	0.29	0.29	1.85	1.72
Cash dividends declared per common share	$ 0.27	$ 0.26	$ 1.07	$ 1.03

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 earnings and earnings per share (EPS) of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary 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 that 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 our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

Note 1. Earnings Per Share Summary

The following table summarizes the diluted earnings per share for Xcel Energy:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
Diluted Earnings (Loss) Per Share	**2012**	**2011**	**2012**	**2011**
Public Service Company of Colorado (PSCo)	$ 0.16	$ 0.18	$ 0.90	$ 0.82
NSP-Minnesota	0.13	0.11	0.70	0.73
Southwestern Public Service Company (SPS)	0.01	0.01	0.22	0.18
NSP-Wisconsin	0.02	0.02	0.10	0.10
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.04	0.04
Regulated utility — continuing operations [(a)]	0.33	0.33	1.96	1.87
Xcel Energy Inc. and other costs	(0.04)	(0.04)	(0.14)	(0.15)
Ongoing[(b)] diluted earnings per share	0.29	0.29	1.82	1.72
Prescription drug tax benefit [(b)]	-	-	0.03	-
GAAP diluted earnings per share	**$ 0.29**	**$ 0.29**	**$ 1.85**	**$ 1.72**

(a) See Note 2.
(b) See Note 6.

PSCo — PSCo's ongoing earnings increased $0.08 per share for 2012. The increase is primarily due to an electric rate increase, effective May 2012, and the impact of warmer summer weather. The increase was partially offset by decreased wholesale revenue due to the expiration of a long-term power sales agreement with Black Hills Corp, higher depreciation expense and operating and maintenance (O&M) expenses.

NSP-Minnesota — NSP-Minnesota's 2012 ongoing earnings decreased $0.03 per share. The decrease is primarily due to the unfavorable impact of warmer than normal winter weather during the first quarter, electric sales decline, higher property taxes, higher O&M expenses and depreciation expense. These decreases were partially offset by the 2012 rate increase and a lower effective tax rate.

SPS — SPS' ongoing earnings increased $0.04 per share for 2012. The increase is the result of rate increases in New Mexico and Texas, effective January 2012, partially offset by the impact of milder weather during the second half of the year, higher depreciation expense and property taxes.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for 2012. Ongoing earnings were positively impacted by rate increases, effective January 2012, offset by higher O&M expenses.

The following table summarizes significant components contributing to the changes in the 2012 EPS compared with the same periods in 2011, which are discussed in more detail later in the release.

Diluted Earnings (Loss) Per Share	Three Months Ended Dec. 31	Twelve Months Ended Dec. 31
2011 GAAP and ongoing[a] diluted earnings per share	$ **0.29**	$ **1.72**
Components of change — 2012 vs. 2011		
Higher electric margins	0.05	0.15
Lower effective tax rate	0.01	0.04
Lower conservation and DSM expenses (generally offset in revenues)	-	0.03
Higher AFUDC - Equity	0.01	0.02
Higher natural gas margins	0.01	0.01
Higher operating and maintenance expenses	(0.04)	(0.05)
Higher depreciation and amortization	(0.05)	(0.04)
Higher taxes (other than income taxes)	(0.01)	(0.04)
Lower (higher) interest charges	0.01	(0.01)
Other, net (including interest and premium on redemption of preferred stock)	0.01	(0.01)
2012 ongoing[a] diluted earnings per share	**0.29**	**1.82**
Prescription drug tax benefit [a]	-	0.03
2012 GAAP diluted earnings per share	$ **0.29**	$ **1.85**

[a] See Note 6.

Note 2. Regulated Utility Results — Continuing Operations

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales while, conversely, 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, from both an energy and demand perspective.

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, and 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 weather sensitive.

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 the time period used by the regulator in establishing estimated volumes in the rate setting process. 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		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
HDD	(6.7) %	(8.7) %	2.1 %	(15.9) %	(1.0) %	(14.8) %
CDD [a]	N/A	N/A	N/A	46.1	38.1	5.7
THI [a]	N/A	N/A	N/A	36.1	37.9	0.2

[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		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
Retail electric	$ (0.002)	$ (0.006)	$ 0.004	$ 0.081	$ 0.080	$ 0.001
Firm natural gas	(0.003)	(0.006)	0.003	(0.033)	0.002	(0.035)
Total	$ (0.005)	$ (0.012)	$ 0.007	$ 0.048	$ 0.082	$ (0.034)

In 2012, Xcel Energy refined its estimate to incorporate the impact of weather on demand charges. As a result, the estimated weather impact on earnings per share for prior periods has been adjusted for comparison purposes.

Sales Growth (Decline) — The following table summarizes Xcel Energy's sales growth (decline) for actual and weather-normalized sales in 2012:

	Three Months Ended Dec. 31	
	Actual	Weather Normalized
Electric residential	0.5 %	0.0 %
Electric commercial and industrial	(0.4)	(0.4)
Total retail electric sales	(0.2)	(0.3)
Firm natural gas sales	0.0	(0.9)

	Twelve Months Ended Dec. 31		Twelve Months Ended Dec. 31 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(1.0) %	(0.1) %	(1.2) %	(0.4) %
Electric commercial and industrial	0.1	0.0	(0.2)	(0.2)
Total retail electric sales	(0.3)	0.0	(0.5)	(0.3)
Firm natural gas sales	(10.6)	(0.3)	(11.0)	(0.8)

Electric — 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 little 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)	2012	2011	2012	2011
Electric revenues	$ 2,011	$ 1,989	$ 8,517	$ 8,767
Electric fuel and purchased power	(899)	(920)	(3,624)	(3,992)
Electric margin	$ 1,112	$ 1,069	$ 4,893	$ 4,775

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

(Millions of Dollars)	Three Months Ended Dec. 31 2012 vs. 2011	Twelve Months Ended Dec. 31 2012 vs. 2011
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, North Dakota, Michigan and Minnesota) [a]	$ 50	$ 125
Demand revenue	7	13
Transmission revenue, net of costs	(7)	13
Conservation and DSM incentive	(6)	12
Estimated impact of weather	4	1
Firm wholesale [b]	(12)	(48)
Retail sales decrease, excluding weather impact	(2)	(6)
Conservation and DSM revenue (offset by expenses)	2	(5)
Other, net	7	13
Total increase in electric margin	$ 43	$ 118

[a] In the fourth quarter of 2011, NSP-Minnesota reduced depreciation expense and revenues by approximately $30 million, representing a full year of depreciation expense, based on the proposed rate case settlements at that time. As a result, NSP-Minnesota recognized higher revenues and depreciation expense, in the fourth quarter of 2012, of approximately $23 million. These settlement provisions did not impact the year over year comparison.

[b] Decrease is primarily due to the expiration of a long-term power sales agreement with Black Hills Corp., effective Jan. 1, 2012.

Natural Gas — The cost of natural gas 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 Dec. 31		Twelve Months Ended Dec. 31	
(Millions of Dollars)	2012	2011	2012	2011
Natural gas revenues	$ 521	$ 560	$ 1,537	$ 1,812
Cost of natural gas sold and transported	(323)	(370)	(881)	(1,164)
Natural gas margin	$ 198	$ 190	$ 656	$ 648

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

(Millions of Dollars)	Three Months Ended Dec. 31 2012 vs. 2011	Twelve Months Ended Dec. 31 2012 vs. 2011
Pipeline system integrity adjustment rider (Colorado) offset by expenses	$ 7	$ 29
Retail rate increase (Colorado, Wisconsin)	-	16
Estimated impact of weather	2	(26)
Conservation and DSM revenue (offset by expenses)	(3)	(17)
Other, net	2	6
Total increase in natural gas margin	$ 8	$ 8

O&M Expenses — O&M expenses increased $34.8 million, or 6.2 percent, for the fourth quarter of 2012 and $35.8 million, or 1.7 percent, for 2012, compared with 2011. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended Dec. 31 2012 vs. 2011	Twelve Months Ended Dec. 31 2012 vs. 2011
Employee benefits	$ (1)	$ 36
Pipeline system integrity costs	5	20
SmartGridCity™	11	11
Prairie Island Extended Power Uprate (EPU)	10	10
Plant generation costs	(12)	(17)
Bad debt expense	(2)	(10)
Labor and contract labor	10	(2)
Other, net	14	(12)
Total increase in O&M expenses	$ 35	$ 36

- Higher employee benefits are mainly due to increased pension expense.
- Higher pipeline system integrity costs relate to increased compliance and inspection initiatives, which in Colorado are recovered through the pipeline system integrity rider.
- See Note 4 for further discussion of SmartGridCity and Prairie Island EPU.
- Lower plant generation costs are primarily attributable to fewer plant overhauls in 2012.
- Higher fourth quarter labor and contract labor costs are largely driven by vegetation management and substation maintenance.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses were flat for the fourth quarter of 2012 and decreased $20.9 million, or 7.4 percent, for 2012, compared with 2011. The lower expenses are primarily attributable to lower gas rider rates, as well as the timing of recovery of electric conservation improvement program expenses at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization increased $37.4 million, or 19.2 percent, for the fourth quarter of 2012 and $35.4 million, or 4.0 percent, for 2012, compared with 2011. NSP-Minnesota recognized higher revenues and higher depreciation expense by approximately $23 million in the fourth quarter of 2012, based on settlements in the Minnesota and South Dakota electric rate cases, which resulted in a year-to-date adjustment lowering depreciation and revenue in the fourth quarter of 2011. Overall, the increase for 2012, compared to 2011 is primarily due to a portion of the Monticello extended power uprate going into service in May 2011 at NSP-Minnesota, the Jones Unit 3 going into service in June 2011 at SPS and normal system expansion across Xcel Energy's service territories.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $6.3 million, or 6.5 percent, for the fourth quarter of 2012 and $34.1 million, or 9.1 percent, for 2012, compared with 2011. The increases are due to an increase in property taxes primarily in Minnesota. Higher property taxes in Colorado related to the electric retail business are being deferred, based on the multi-year rate settlement approved by the Colorado Public Utilities Commission (CPUC) in May 2012.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased $9.8 million for the fourth quarter of 2012 and $18.8 million for 2012, compared with 2011. The increases are primarily due to the expansion of PSCo's transmission facilities, additional construction related to the Colorado Clean Air Clean Jobs Act (CACJA) and life extension work at the Prairie Island nuclear generating plant.

Interest Charges — Interest charges decreased $8.3 million, or 5.4 percent, for the fourth quarter of 2012 and increased $10.5 million, or 1.8 percent, for 2012, compared with 2011. The overall increase is due to higher long-term debt levels to fund investment in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations decreased $8.4 million for the fourth quarter of 2012, compared with the same period in 2011. The decrease in income tax expense was primarily due to a decrease in pretax income in 2012 and a tax benefit related to the reversal of a tax valuation allowance in 2012. The effective tax rate for continuing operations was 33.3 percent for the fourth quarter of 2012 compared with 35.8 percent for the same period in 2011. The lower effective tax rate for 2012 was primarily due to the adjustment referenced above. The effective tax rate would have been 34.5 percent for the fourth quarter of 2012 without this tax benefit.

Income tax expense for continuing operations decreased $18.1 million for 2012, compared with 2011. The decrease in income tax expense was primarily due to a tax benefit of approximately $14.9 million associated with a carryback and a tax benefit of $17 million related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. These were partially offset by higher pretax income in 2012. The effective tax rate for continuing operations was 33.2 percent for 2012 compared with 35.8 percent for 2011. The lower effective tax rate for 2012 was primarily due to the adjustments referenced above. The effective tax rate would have been 35.6 percent for 2012 without these tax benefits.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Dec. 31, 2012	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1 %
Short-term debt	0.6	3
Long-term debt	10.1	51
Total debt	11.0	55
Common equity	8.9	45
Total capitalization	$ 19.9	100 %

Credit Facilities — As of Jan. 29, 2013, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn [(a)]	Available	Cash	Liquidity	Maturity
Xcel Energy Inc.	$ 800.0	$ 351.0	$ 449.0	$ 0.2	$ 449.2	July 2017
PSCo	700.0	169.0	531.0	1.1	532.1	July 2017
NSP-Minnesota	500.0	323.2	176.8	0.6	177.4	July 2017
SPS	300.0	35.0	265.0	0.9	265.9	July 2017
NSP-Wisconsin	150.0	41.0	109.0	0.1	109.1	July 2017
Total	$ 2,450.0	$ 919.2	$ 1,530.8	$ 2.9	$ 1,533.7	

[(a)] Includes outstanding commercial paper and letters of credit.

Credit Ratings — Access to reasonably priced capital markets is dependent in part on credit and 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. 29, 2013, 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	Baa1	BBB+	BBB+
Xcel Energy Inc.	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	A-	A
NSP-Minnesota	Senior Secured Debt	A1	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F2
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A1	A	A+
NSP-Wisconsin	Commercial Paper	P-2	A-2	F2
PSCo	Senior Unsecured Debt	Baa1	A-	A-
PSCo	Senior Secured Debt	A2	A	A
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa2	A-	BBB+
SPS	Senior Secured Debt	A3	A-	A-
SPS	Commercial Paper	P-2	A-2	F2

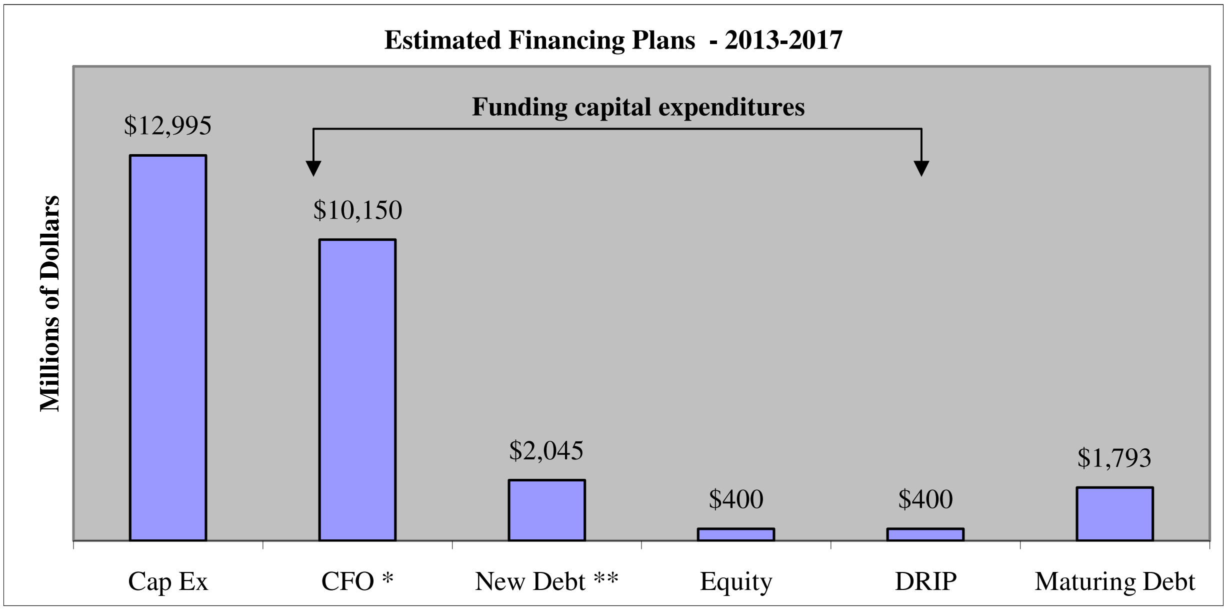
The highest credit rating for debt is Aaa/AAA and the lowest investment grade rating is Baa3/BBB-. The highest rating for commercial paper is P-1/A-1/F-1 and the lowest rating is P-3/A-3/F-3. A security rating is not a recommendation to buy, sell or hold securities. Ratings are subject to revision or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

Capital Expenditures — The 2012 actual and the current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2013 through 2017 are shown in the table below. The capital expenditure forecast has been revised to reflect the termination of the Prairie Island EPU.

	Actual	Forecast				
(Millions of Dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
By Subsidiary						
NSP-Minnesota	$ 1,018	$ 1,395	$ 1,135	$ 910	$ 925	$ 1,080
PSCo	887	1,075	1,000	850	800	840
SPS	389	490	400	305	300	345
NSP-Wisconsin	155	180	240	245	230	235
WYCO	1	15	-	-	-	-
Total capital expenditures	$ 2,450	$ 3,155	$ 2,775	$ 2,310	$ 2,255	$ 2,500
By Function	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric generation	$ 772	$ 1,025	$ 710	$ 550	$ 465	$ 570
Electric transmission	734	1,010	870	650	635	770
Electric distribution	486	515	525	525	535	545
Natural gas	247	355	365	335	325	320
Nuclear fuel	53	95	155	100	140	145
Other	158	155	150	150	155	150
Total capital expenditures	$ 2,450	$ 3,155	$ 2,775	$ 2,310	$ 2,255	$ 2,500
By Project	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Other capital expenditures	$ 1,720	$ 1,710	$ 1,610	$ 1,555	$ 1,600	$ 1,755
PSCo CACJA	189	345	235	90	15	-
Other major transmission projects	179	245	260	175	320	415
CapX2020 transmission project	170	350	295	140	-	-
Natural gas pipeline replacement	100	140	170	190	130	135
Nuclear fuel	53	95	155	100	140	145
Nuclear capacity increases and life extension	39	270	50	60	50	50
Total capital expenditures	$ 2,450	$ 3,155	$ 2,775	$ 2,310	$ 2,255	$ 2,500

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margins, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with future environmental requirements, renewable portfolio standards, and merger, acquisition and divestiture opportunities to support corporate strategies.

Financing **—** Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction 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 2013 through 2017 are shown in the table below. The financing plan has been revised to reflect the termination of the Prairie Island EPU and the impacts of extended bonus depreciation under the recent federal tax bill.



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

During 2012, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In June, SPS issued $100 million of 30-year first mortgage bonds with a coupon of 4.50 percent.
- In August, NSP-Minnesota issued $300 million of 10-year first mortgage bonds with a coupon of 2.15 percent, and $500 million of 30-year first mortgage bonds with a coupon of 3.40 percent.
- In September, PSCo issued $300 million of 10-year first mortgage bonds with a coupon of 2.25 percent, and $500 million of 30-year first mortgage bonds with a coupon of 3.60 percent.
- In October, NSP-Wisconsin issued $100 million of 30-year first mortgage bonds with a coupon of 3.70 percent.

During 2013, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- NSP-Minnesota may issue approximately $400 million of first mortgage bonds in the first half of 2013.
- PSCo may issue approximately $500 million of first mortgage bonds in the first half of 2013.
- SPS may issue approximately $100 million of first mortgage bonds in the first half of 2013.

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

Note 4. Rates and Regulation

NSP-Minnesota – Minnesota 2012 Electric Rate Case — In November 2012, NSP-Minnesota filed a request with the Minnesota Public Utilities Commission (MPUC) for an increase in annual revenues of approximately $285 million, or 10.7 percent. The rate filing is based on a 2013 forecast test year, a requested return on equity (ROE) of 10.6 percent, an average electric rate base of approximately $6.3 billion and an equity ratio of 52.56 percent.

In December 2012, the MPUC accepted the filing as complete and approved the interim rates of approximately $251 million, as requested, effective Jan. 1, 2013, subject to refund.

The procedural schedule is as follows:

- Intervenor Direct Testimony – Feb. 28, 2013
- Rebuttal Testimony – March 25, 2013
- Surrebuttal Testimony – April 12, 2013
- Evidentiary Hearing – April 18 – 24, 2013
- Initial Brief – May 15, 2013
- Reply Brief and Findings of Fact – May 30, 2013
- Administrative Law Judge (ALJ) Report – July 3, 2013
- MPUC Order – Anticipated by September 2013

Prairie Island Nuclear Plant EPU — In 2009, the MPUC granted NSP-Minnesota a Certificate of Need (CON) for an EPU project at the Prairie Island nuclear generating plant. The total estimated cost of the EPU was $294 million, of which approximately $77.6 million has been incurred, including AFUDC of approximately $13.3 million. Subsequently, NSP-Minnesota filed a resource plan update and a change of circumstances (COC) filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In December 2012, the MPUC voted unanimously that no party had shown cause to prevent termination of the EPU CON. The MPUC is expected to issue an order terminating the EPU CON in early 2013.

NSP-Minnesota plans to address recovery of incurred costs in the next rate case for each of the NSP-Minnesota jurisdictions and to file a request with the FERC for approval to recover a portion of the costs from NSP-Wisconsin through the Interchange Agreement. NSP-Wisconsin plans to seek cost recovery in a future rate case. Based on the outcome of the MPUC decision, EPU costs incurred to date were compared to the discounted value of the estimated future rate recovery based on past jurisdictional precedent, resulting in a $10.1 million pretax charge in December 2012.

NSP-Minnesota – North Dakota 2012 Electric Rate Case — In December 2012, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) for an increase in annual retail electric revenues of approximately $16.9 million, or 9.25 percent. The rate filing is based on a 2013 forecast test year, a requested ROE of 10.6 percent, an electric rate base of approximately $377.6 million and an equity ratio of 52.56 percent.

In January 2013, the NDPSC approved an interim electric increase of $14.7 million, effective Feb. 16, 2013, subject to refund. A final NDPSC decision on the case is expected in the third quarter of 2013.

NSP-Minnesota – South Dakota 2012 Electric Rate Case — In June 2012, NSP-Minnesota filed a request with the South Dakota Public Utilities Commission (SDPUC) to increase electric rates by $19.4 million annually. The request was based on a 2011 historic test year adjusted for known and measurable changes for 2012 and 2013, a requested ROE of 10.65 percent, an average rate base of $367.5 million and an equity ratio of 52.89 percent.

In December 2012, the procedural schedule was suspended to allow time to construct a potential settlement agreement between NSP-Minnesota and the SDPUC Staff. Interim rates of $19.4 million went into effect on Jan. 1, 2013, subject to refund. A SDPUC decision is expected in the first half of 2013.

NSP-Wisconsin – 2012 Electric and Gas Rate Case — In June 2012, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase rates for electric and natural gas service, effective Jan. 1, 2013. NSP-Wisconsin requested an overall increase in annual electric rates of $39.1 million, or 6.7 percent, and an increase in natural gas rates of $5.3 million, or 4.9 percent.

The electric rate filing was based on a 2013 forecast test year, a ROE of 10.40 percent, an equity ratio of 52.50 percent and an average 2013 electric rate base of approximately $788.6 million. The natural gas rate request was solely due to a proposal to recover the initial costs associated with the environmental cleanup of a site in Ashland, Wis.

In December 2012, the PSCW approved an electric rate increase of approximately $35.5 million, or 6.1 percent, based on a 10.4 percent ROE and an equity ratio of 52.50 percent. The PSCW also approved a natural gas rate increase of $2.7 million, or 2.5 percent, to begin recovering costs associated with the cleanup in Ashland, Wis. Final rates were implemented on Jan. 1, 2013.

PSCo – Colorado 2012 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the Colorado Public Utilities Commission (CPUC) to increase Colorado retail natural gas rates by $48.5 million in 2013 with subsequent step increases of $9.9 million in 2014 and $12.1 million in 2015. PSCo also requested to increase Colorado retail steam rates by $1.6 million in 2013 with subsequent step increases of $0.9 million in 2014 and $2.3 million in 2015. Both requests are based on a 2013 forecast test year, a 10.5 percent ROE, a rate base of $1.3 billion for natural gas and $21 million for steam and an equity ratio of 56 percent. Final rates are expected to be effective in the third quarter of 2013.

PSCo is requesting an extension of its Pipeline System Integrity Adjustment (PSIA) rider mechanism to collect the costs of accelerated pipeline integrity efforts, including system renewal projects. PSCo estimates that the PSIA will increase by $26.8 million in 2014 with a subsequent step increase of $24.7 million in 2015 in addition to the proposed changes in base rate revenue. In conjunction with the multi-year base rate step increases, PSCo is proposing a stay-out provision and an earnings test through the end of 2015.

PSCo – SmartGridCity™ (SGC) Cost Recovery — PSCo requested recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred to develop and operate SGC as part of its 2010 electric rate case. In February 2011, the CPUC allowed recovery of approximately $28 million of the capital cost and all of the O&M costs. In December 2011, PSCo requested CPUC approval for the recovery of the remaining capital investment in SGC and also provided the additional information requested. On Jan. 17, 2013, the ALJ recommended denial of PSCo's request for recovery of the remaining portion of the SGC investment. Parties will have an opportunity to appeal the ALJ's recommended decision by filing exceptions with the CPUC. If no exceptions are filed within 20 days, the recommended decision will become effective. As a result of the ALJ's recommended decision, PSCo recognized a $10.7 million pre-tax charge in 2012, representing the net book value of the disallowed investment.

PSCo Resource Plan — In July 2012, PSCo filed two separate applications to update its resource plan. The first was an application to purchase Brush Power, LLC and all of its assets including Brush generating Units 1, 3 and 4 for a total purchase price of approximately $75 million. The Brush units currently provide 237 MW of natural gas fueled capacity and energy to PSCo under Purchased Power Agreements (PPAs) that are set to expire in 2017 for Brush Unit 1 and Brush Unit 3, and 2022 for Brush Unit 4.

The second application sought approval to retire Arapahoe Unit 4, a 109 MW coal-fired company-owned generating station at the end of 2013. This was presented as an alternative to permanently fuel switching Arapahoe Unit 4 to natural gas and instead replacing the capacity and associated energy with a natural gas PPA with an existing generator.

In September 2012, the FERC approved the acquisition of Brush Power, LLC. However, in December 2012, the CPUC denied approval of the acquisition in oral deliberations due to the risks associated with the transaction. PSCo has the ability to terminate the transaction based on the regulatory outcome. The CPUC also denied PSCo's proposal to retire Arapahoe 4 by the end of 2013; however, this proposal could be revisited.

SPS – Texas 2012 Electric Rate Case — In November 2012, SPS filed an electric rate case in Texas with the Public Utility Commission of Texas for an increase in annual revenue of approximately $90.2 million. The rate filing is based on a historic twelve month test year ended June 30, 2012 adjusted for known and measurable changes, a requested ROE of 10.65 percent, an electric rate base of $1.15 billion and an equity ratio of 52 percent.

The procedural schedule is as follows:

- Intervenor Direct Testimony – Feb. 22, 2013
- Staff Direct Testimony – March 1, 2013
- SPS Rebuttal Testimony – March 15, 2013
- Hearing Starts – March 26, 2013
- The procedural order also establishes July 1, 2013 as the latest date rates from this case will become effective.

SPS – New Mexico 2012 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the New Mexico Public Regulation Commission (NMPRC) for an increase in annual revenue of approximately $45.9 million. The rate filing is based on a 2014 forecast test year, a requested ROE of 10.65 percent, a jurisdictional electric rate base of $365.5 million and an equity ratio of 53.89 percent. A NMPRC decision is expected in the fourth quarter of 2013 with the implementation of final rates anticipated in the first quarter of 2014.

Note 5. Xcel Energy Earnings Guidance

Xcel Energy's 2013 earnings guidance is $1.85 to $1.95 per share. Key assumptions related to 2013 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales are projected to grow approximately 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline by approximately 1 percent.
- Rider revenue recovery for certain projects have been rolled into base rates, therefore the change is no longer meaningful.
- O&M expenses are projected to increase approximately 4 percent to 5 percent over 2012 levels.
- Depreciation expense is projected to increase $75 million to $85 million over 2012 levels.
- Property taxes are projected to increase approximately $35 million to $40 million over 2012 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $30 million to $35 million from 2012 levels.
- AFUDC — equity is projected to increase approximately $15 million to $20 million over 2012 levels.
- The effective tax rate is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 490 million to 500 million shares.

Note 6. Non-GAAP Reconciliation

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. 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:

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(Thousands of Dollars)	**2012**	**2011**	**2012**	**2011**
Ongoing earnings	**$ 140,208**	**$ 140,941**	**$ 888,255**	**$ 841,374**
Prescription drug tax benefit	-	-	16,944	-
Total continuing operations	**140,208**	**140,941**	**905,199**	**841,374**
(Loss) income from discontinued operations	(38)	(432)	30	(202)
GAAP earnings	**$ 140,170**	**$ 140,509**	**$ 905,229**	**$ 841,172**

Impact of the Patient Protection and Affordable Care Act **—** In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to the federal subsidies during the first quarter of 2010.

In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million of income tax benefit.

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

	Three Months Ended Dec. 31	
	2012	2011
Operating revenues:		
Electric and natural gas revenues	$ 2,531,489	$ 2,548,909
Other	19,646	19,501
Total operating revenues	2,551,135	2,568,410
Income from continuing operations	140,208	140,941
Loss from discontinued operations	(38)	(432)
Net income	$ 140,170	$ 140,509
Earnings available to common shareholders	$ 140,170	$ 140,509
Weighted average diluted common shares outstanding	489,136	486,991
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 0.33	$ 0.33
Xcel Energy Inc. and other costs	(0.04)	(0.04)
Ongoing[a] diluted earnings per share	0.29	0.29
Prescription drug tax benefit [a]	-	-
GAAP diluted earnings per share	$ **0.29**	$ **0.29**

	Twelve Months Ended Dec. 31	
	2012	2011
Operating revenues:		
Electric and natural gas revenues	$ 10,054,670	$ 10,578,519
Other	73,553	76,251
Total operating revenues	10,128,223	10,654,770
Income from continuing operations	905,199	841,374
Income (loss) from discontinued operations	30	(202)
Net income	$ 905,229	$ 841,172
Earnings available to common shareholders	$ 905,229	$ 834,378
Weighted average diluted common shares outstanding	488,434	485,615
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 1.96	$ 1.87
Xcel Energy Inc. and other costs	(0.14)	(0.15)
Ongoing[a] diluted earnings per share	1.82	1.72
Prescription drug tax benefit [a]	0.03	-
GAAP diluted earnings per share	**$ 1.85**	**$ 1.72**
Book value per share	$ 18.19	$ 17.44

[a] See Note 6.