414 Nicollet Mall
Minneapolis, MN 55401

Aug. 1, 2013

XCEL ENERGY
SECOND QUARTER 2013 EARNINGS REPORT

- 2013 second quarter earnings per share were $0.40 compared with $0.38 per share in 2012.
- Xcel Energy reaffirms 2013 earnings guidance of $1.85 to $1.95 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2013 second quarter earnings of $197 million, or $0.40 per share, compared with 2012 earnings of $183 million, or $0.38 per share.

Second quarter 2013 earnings were favorably impacted by increased electric and natural gas margins. The increase in electric margin was mainly due to rate increases in Colorado, Wisconsin, South Dakota and Texas, along with interim rate increases, subject to refund, in Minnesota and North Dakota. Natural gas margins were positively impacted by cooler weather compared with the second quarter of last year. These positive drivers were partially offset by higher operating and maintenance expenses and depreciation and amortization, reflecting our continued infrastructure investment in our utility business.

"In addition to a solid quarter financially, we continued to demonstrate our strong operational capabilities," said Ben Fowke, Chairman, President and Chief Executive Officer. "In June, Minnesota experienced several severe thunderstorms which impacted more than 600,000 of our customers. We coordinated a workforce of 1,100 linemen from 14 states and several hundred support personnel to handle the state's record electrical outage. As a result, power was restored to 96 percent of our customers within three days. I'm proud of all the workers who labored tirelessly to complete this effort in an orderly, safe and timely fashion."

"Regarding developments in our Minnesota electric rate case, the Administrative Law Judge's recommendation provided for approximately $127 million in revenue, well below our request," stated Fowke. "However, the ALJ also recommended approximately $34 million in additional cost deferrals. The additional deferrals combined with favorable weather and certain other items position Xcel Energy to deliver 2013 earnings within the guidance range of $1.85 to $1.95 per share."

At 10:00 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:	(877) 941-6009
International Dial-In:	(480) 629-9722
Conference ID:	4628633

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. CDT on Aug. 1 through 11:59 p.m. CDT on Aug. 2.

Replay Numbers

US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4628633#

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, 2012 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(amounts in thousands, except per share data)

	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	2013	2012
Operating revenues				
Electric	$ 2,219,877	$ 2,036,829	$ 4,312,073	$ 3,973,611
Natural gas	341,321	221,313	1,010,917	842,348
Other	17,715	16,526	38,772	36,788
Total operating revenues	2,578,913	2,274,668	5,361,762	4,852,747
Operating expenses				
Electric fuel and purchased power	1,011,044	854,373	1,936,087	1,718,353
Cost of natural gas sold and transported	188,765	89,759	628,140	507,705
Cost of sales — other	7,881	5,944	16,292	13,248
Operating and maintenance expenses	562,557	534,014	1,091,788	1,044,698
Conservation and demand side management program expenses	60,445	58,615	124,477	122,322
Depreciation and amortization	243,934	226,641	492,640	455,313
Taxes (other than income taxes)	102,051	99,632	215,478	205,256
Total operating expenses	2,176,677	1,868,978	4,504,902	4,066,895
Operating income	402,236	405,690	856,860	785,852
Other income, net	413	728	4,335	4,465
Equity earnings of unconsolidated subsidiaries	7,529	7,502	15,106	14,660
Allowance for funds used during construction — equity	22,109	15,194	41,863	28,644
Interest charges and financing costs				
Interest charges — includes other financing costs of $12,229, $6,036, $18,038 and $12,116, respectively	146,828	151,921	286,441	303,751
Allowance for funds used during construction — debt	(10,316)	(7,683)	(19,074)	(14,290)
Total interest charges and financing costs	136,512	144,238	267,367	289,461
Income from continuing operations before income taxes	295,775	284,876	650,797	544,160
Income taxes	98,893	101,801	217,327	177,316
Income from continuing operations	196,882	183,075	433,470	366,844
(Loss) income from discontinued operations, net of tax	(25)	(15)	(43)	109
Net income	$ 196,857	$ 183,060	$ 433,427	$ 366,953
Weighted average common shares outstanding:				
Basic	497,747	487,717	493,786	487,538
Diluted	498,036	488,017	494,303	488,006
Earnings per average common share:				
Basic	$ 0.40	$ 0.38	$ 0.88	$ 0.75
Diluted	0.40	0.38	0.88	0.75
Cash dividends declared per common share	$ 0.28	$ 0.27	$ 0.55	$ 0.53

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 generally accepted accounting principles (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 June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2013**	**2012**	**2013**	**2012**
Public Service Company of Colorado (PSCo)	$ 0.20	$ 0.20	$ 0.43	$ 0.39
NSP-Minnesota	0.16	0.13	0.37	0.29
Southwestern Public Service Company (SPS)	0.05	0.06	0.08	0.08
NSP-Wisconsin	0.02	0.01	0.06	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility — continuing operations [(a)]	0.44	0.41	0.96	0.82
Xcel Energy Inc. and other costs	(0.04)	(0.03)	(0.08)	(0.07)
GAAP diluted earnings per share	**$ 0.40**	**$ 0.38**	**$ 0.88**	**$ 0.75**

(a) See Note 2.

PSCo — PSCo's earnings were flat for the second quarter of 2013 and increased $0.04 per share for the six months ended June 30, 2013. Higher electric and natural gas margins and lower interest charges were offset by higher depreciation and operating and maintenance (O&M) expenses. Higher margins resulted from electric rate increases, effective May 2012 and January 2013, and increased natural gas margins due to cooler weather compared to the prior year.

NSP-Minnesota — NSP-Minnesota's earnings increased $0.03 per share for the second quarter of 2013 and $0.08 per share for the six months ended June 30, 2013. Earnings were positively impacted by the Minnesota and North Dakota interim electric rates, subject to refund, an electric rate increase in South Dakota and lower interest charges. Further, natural gas margins increased due to cooler weather which contributed approximately $0.01 per share and $0.04 per share for the three and six month periods, respectively. These factors were partially offset by higher O&M expenses and depreciation.

SPS — SPS' earnings decreased $0.01 per share for the second quarter of 2013 and were flat for the six months ended June 30, 2013. Rate increases in Texas, effective May 2013, did not fully offset higher O&M expenses, depreciation and interest charges.

NSP-Wisconsin — NSP-Wisconsin's earnings increased $0.01 per share for the second quarter of 2013 and $0.02 per share for the six months ended June 30, 2013. Higher earnings from electric and gas rates, effective January 2013, and the effect of cooler weather were partially offset by higher depreciation and O&M expenses.

The following table summarizes significant components contributing to the changes in 2013 EPS compared with the same period in 2012, which are discussed in more detail later in the release:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2012 GAAP diluted earnings per share	**$ 0.38**	**$ 0.75**
Components of change — 2013 vs. 2012		
Higher electric margins	0.03	0.15
Higher natural gas margins	0.03	0.06
Higher AFUDC - Equity	0.01	0.03
Lower interest charges	0.01	0.02
Lower effective tax rate	0.01	-
Higher taxes (other than income taxes)	-	(0.01)
Higher operating and maintenance expenses	(0.04)	(0.06)
Higher depreciation and amortization	(0.02)	(0.05)
Dilution from direct stock purchase plan and benefit plans	(0.01)	(0.01)
2013 GAAP diluted earnings per share	**$ 0.40**	**$ 0.88**

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 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 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 June 30			Six Months Ended June 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
HDD	22.5 %	(33.1) %	84.4 %	7.2 %	(21.4) %	35.6 %
CDD	52.2	79.9	(16.1)	51.8	83.2	(18.0)
THI	6.6	40.1	(28.0)	6.5	45.7	(30.9)

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

	Three Months Ended June 30			Six Months Ended June 30		
	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012	2013 vs. Normal	2012 vs. Normal	2013 vs. 2012
Retail electric	$ 0.027	$ 0.032	$ (0.005)	$ 0.031	$ 0.007	$ 0.024
Firm natural gas	0.007	(0.008)	0.015	0.016	(0.029)	0.045
Total	$ 0.034	$ 0.024	$ 0.010	$ 0.047	$ (0.022)	$ 0.069

Sales Growth (Decline) — The following tables summarize Xcel Energy's sales growth (decline) for actual and weather-normalized sales in 2013:

	Three Months Ended June 30	
	Actual	Weather Normalized
Electric residential	0.1 %	0.3 %
Electric commercial and industrial	(0.9)	(0.5)
Total retail electric sales	(0.6)	(0.2)
Firm natural gas sales [(a)]	66.0	17.2

	Six Months Ended June 30		Six Months Ended June 30 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	2.7 %	0.1 %	3.3 %	0.7 %
Electric commercial and industrial	(0.4)	(0.6)	0.1	(0.1)
Total retail electric sales	0.4	(0.4)	0.9	0.1
Firm natural gas sales [(a)]	31.3	3.7	32.4	4.6

(a) As normal weather conditions are typically defined as a 30-year average of actual historical weather conditions, significant weather variations in periods of low demand may result in large percentage changes on small volumes.

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 June 30		Six Months Ended June 30	
(Millions of Dollars)	2013	2012	2013	2012
Electric revenues	$ 2,220	$ 2,037	$ 4,312	$ 3,974
Electric fuel and purchased power	(1,011)	(854)	(1,936)	(1,718)
Electric margin	$ 1,209	$ 1,183	$ 2,376	$ 2,256

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

(Millions of Dollars)	Three Months Ended June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Retail rate increases (Minnesota interim, Colorado, Wisconsin, South Dakota, Texas and North Dakota interim) [(a)]	$ 56	$ 131
Transmission revenue, net of costs	10	21
PSCo earnings test refund obligation	(9)	(9)
Conservation and demand side management program incentives	(9)	(8)
Firm wholesale	(8)	(13)
Estimated impact of weather	(3)	19
Other, net	(11)	(21)
Total increase in electric margin	$ 26	$ 120

(a) NSP-Minnesota recognized a reserve for revenue subject to refund of approximately $31 million and $47 million for the three and six month periods ended June 30, 2013, respectively. See Note 4 for additional discussion.

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 June 30		Six Months Ended June 30	
(Millions of Dollars)	**2013**	**2012**	**2013**	**2012**
Natural gas revenues	$ 341	$ 221	$ 1,011	$ 842
Cost of natural gas sold and transported	(189)	(90)	(628)	(508)
Natural gas margin	$ 152	$ 131	$ 383	$ 334

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

(Millions of Dollars)	Three Months Ended June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Estimated impact of weather	$ 12	$ 34
Retail sales growth	7	6
Conservation and demand side management program revenues (offset by expenses)	2	5
Other, net	-	4
Total increase in natural gas margin	$ 21	$ 49

O&M Expenses — O&M expenses increased $28.5 million, or 5.3 percent, for the second quarter of 2013 and $47.1 million, or 4.5 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended June 30 2013 vs. 2012	Six Months Ended June 30 2013 vs. 2012
Other electric and gas distribution expenses	$ 12	$ 13
Nuclear plant operations and amortization	9	18
Transmission costs	5	9
NSP-Minnesota storm damage restoration	4	4
Employee benefits	(2)	7
Other, net	1	(4)
Total increase in O&M expenses	$ 29	$ 47

- Other electric and gas distribution expenses were primarily driven by increased maintenance activities;
- Costs related to nuclear plant operations and amortization increased mainly due to operational initiatives;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs;
- Storm damage restoration was due to power outages experienced during the second quarter of 2013;
- Higher year-to-date employee benefits related primarily to increased pension expense.

Depreciation and Amortization — Depreciation and amortization increased $17.3 million, or 7.6 percent, for the second quarter of 2013 and $37.3 million, or 8.2 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are primarily attributable to normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $2.4 million, or 2.4 percent, for the second quarter of 2013 and $10.2 million, or 5.0 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are due to higher property taxes primarily in Minnesota, Colorado and Texas. Increased 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 with amortization of the deferral beginning in 2013.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased $9.5 million for the second quarter of 2013 and $18.0 million for the six months ended June 30, 2013 compared with the same periods in 2012. The increases are due to construction related to the Clean Air Clean Jobs Act, the expansion of transmission facilities and other capital projects.

Interest Charges — Interest charges decreased $5.1 million, or 3.4 percent, for the second quarter of 2013 and $17.3 million, or 5.7 percent, for the six months ended June 30, 2013 compared with the same periods in 2012. The decreases are due to lower interest rates, primarily related to refinancings, partially offset by higher long-term debt levels to fund investments in utility operations and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Income Taxes — Income tax expense for continuing operations decreased $2.9 million for the second quarter of 2013 compared with the same period in 2012. The decrease in income tax expense was primarily due to increased plant-related adjustments. The effective tax rate for continuing operations was 33.4 percent for the second quarter of 2013 compared with 35.7 percent for the same period in 2012. The lower effective tax rate for 2013 was primarily due to a tax benefit for a carryback related to 2013 and increased permanent plant-related adjustments in 2013.

Income tax expense for continuing operations increased $40.0 million for the first six months of 2013 compared with the same period in 2012. The increase in income tax expense was primarily due to higher pretax earnings. The effective tax rate for continuing operations was 33.4 percent for the six months ended June 30, 2013 compared with 32.6 percent for the same period in 2012. The lower effective tax rate for 2012 was primarily due to a discrete tax benefit of approximately $15 million for a carryback in 2012, partially offset by a tax benefit for a carryback claim related to 2013 and increased permanent plant-related adjustments in 2013.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	June 30, 2013	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1 %
Short-term debt	0.4	2
Long-term debt	10.8	52
Total debt	11.5	55
Common equity	9.3	45
Total capitalization	$ 20.8	100 %

Credit Facilities — As of July 25, 2013, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 800.0	$ 240.0	$ 560.0	$ 0.4	$ 560.4
PSCo	700.0	4.6	695.4	0.6	696.0
NSP-Minnesota	500.0	101.2	398.8	0.2	399.0
SPS	300.0	134.0	166.0	0.5	166.5
NSP-Wisconsin	150.0	12.0	138.0	0.5	138.5
Total	$ 2,450.0	$ 491.8	$ 1,958.2	$ 2.2	$ 1,960.4

[a] These credit facilities expire in July 2017.

[b] Includes outstanding commercial paper and letters of credit.

Credit Ratings — Access to the capital market at reasonable terms is dependent in part on credit ratings. The following ratings reflect the views of Moody's Investors Service (Moody's), Standard & Poor's Rating Services (Standard & Poor's), and Fitch Ratings (Fitch).

As of July 25, 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.

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.

During 2013, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In March, PSCo issued $250 million of 2.50 percent first mortgage bonds due March 15, 2023 and $250 million of 3.95 percent first mortgage bonds due March 15, 2043.
- In May, Xcel Energy Inc. issued $450 million of 0.75 percent senior unsecured notes due May 9, 2016.
- In May, NSP-Minnesota issued $400 million of 2.60 percent first mortgage bonds due May 15, 2023.

In addition, SPS may issue approximately $100 million of first mortgage bonds in the third quarter of 2013.

In March 2013, Xcel Energy Inc. filed a prospectus supplement under which it may sell up to $400 million of its common stock through an at-the-market offering program. As of June 30, 2013, Xcel Energy Inc. sold 7.7 million shares of common stock with net proceeds of $223 million.

On May 31, 2013, Xcel Energy Inc. redeemed the entire $400 million principal amount of the 7.60 percent junior subordinated notes. Upon redemption, Xcel Energy Inc. recognized $6.3 million of related unamortized debt issuance costs as interest charges.

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 January 2013, interim rates of approximately $251 million became effective, subject to refund.

In March 2013, NSP-Minnesota filed rebuttal testimony and revised the requested annual revenue increase to approximately $219.7 million, or 8.23 percent, based on an ROE of 10.6 percent, a rate base of approximately $6.3 billion and an equity ratio of 52.56 percent. The updated request reflects alternate proposals in several key areas including:

- Deferral of depreciation expenses and property taxes related to Sherco Unit 3 for 2012 and 2013 and removal of avoided 2013 O&M expense due to the extended outage at Sherco Unit 3.
- Removal of Monticello 2013 license costs from plant in service and deferral of 2013 depreciation expense for the primary Monticello life cycle management (LCM) / extended power uprate (EPU) project until after an MPUC order finding the costs prudent.
- Removal of Prairie Island EPU project costs, reflecting the MPUC decision to cancel the project in December 2012.
- Adjustments to compensation and benefits recovery including Annual Incentive Plan (AIP) to reflect prior MPUC decisions establishing a limitation at 15 percent of base pay using a four-year average AIP target, pension expense and active healthcare costs.
- Adjustment of pension recoveries to reflect amortized recovery of 2008 market losses.
- Recovery of coal pile and ash pond remediation costs at the Black Dog plant through a 15 year amortization.
- Updated forecast for property taxes.
- Updated forecast with 6 months of actual sales, customer and weather data through December 2012, and updated economic assumptions based on a December 2012 economic forecast, proposing a refund if sales are higher than forecast on a weather-normalized basis.
- Correction to the original filing and other adjustments.

In April 2013, intervenors filed surrebuttal testimony, including the Minnesota Department of Commerce (DOC), Office of Attorney General (OAG), Minnesota Chamber (MCC), Xcel Large Industrials (XLI), Commercial Group, Industrial, Commercial and Institutional Customers, and Energy Cents Coalition. The DOC recommended a revenue increase of $89.6 million, based on a 9.83 percent ROE, an average electric rate base of approximately $6.1 billion, and an equity ratio of 52.56 percent. Subsequently, the DOC's recommendation was revised to approximately $98.6 million, largely to reflect updated information.

In its surrebuttal testimony, the OAG recommended no recovery for the Prairie Island EPU project, stating it should have been written off in 2012 when cancellation of the project was approved by the MPUC. The DOC is also not supportive of recovery of the Prairie Island EPU cancelled EPU costs. The OAG suggests pension recovery in rates exceeds benefit payout because of changes made to benefit plans and recommends correction for an alleged over-collection of funds to pay for future benefits which may never be paid out. The OAG supports the DOC in adjustments to recovery of annual incentive compensation and does not find NSP-Minnesota's Sherco Unit 3 proposal warranted. XLI and MCC also opposed recovery of Sherco Unit 3 costs and Monticello EPU costs.

Through the hearing and briefing process, NSP-Minnesota revised its rate request to approximately $209 million to reflect updated property tax information, resolution of concerns regarding Wisconsin wholesale customers and other adjustments. The $209 million revenue requirement reflects a requested deficiency of $259 million combined with $50 million of rate mitigation through deferral mechanisms.

ALJ Recommendation

On July 3, 2013, the Minnesota ALJ issued her report and recommended a rate increase of approximately $127 million, based on a ROE of 9.83 percent, an equity ratio of 52.56 percent and an electric rate base of $6.233 billion. In addition, the ALJ recommendation included approximately $51 million in deferrals of which we estimate $34 million will affect our net income. The deferrals are related to Sherco Unit 3 and pension.

The ALJ indicated that Sherco Unit 3 should be considered "used and useful" for rate making purposes, but that a portion of the Monticello LCM/EPU would not be considered "used and useful" until we obtain our uprate license from the Nuclear Regulatory Commission. The ALJ also found that the prudency of the cost increases for the Monticello LCM/EPU project and cost recovery for the cancelled Prairie Island EPU project should be determined in the next Minnesota rate case. In addition, the ALJ recommended accepting NSP-Minnesota's position on the inclusion of the pension market loss and incentive compensation and the DOC's position on the sales forecast.

The table below reconciles the final position of NSP-Minnesota, the DOC and the ALJ.

(Millions of Dollars)	NSP-Minnesota Request	DOC Recommendation	ALJ Recommendation
NSP-Minnesota original request	$ 285	$ 285	$ 285
ROE	-	(43)	(43)
Sherco Unit 3	(35)	(40)	(38)
Reduced recovery for nuclear plants	(11)	(9)	(14)
Incentive compensation	(3)	(20)	(4)
Sales forecast	(1)	(26)	(26)
Pension	(10)	(25)	(13)
Employee benefits	(4)	(6)	(6)
Black Dog remediation	(5)	(5)	(5)
NSP-Wisconsin wholesale allocation	(7)	(7)	(7)
Other, net	-	(5)	(2)
Recommended rate increase	209	99	127
Preliminary estimated impact of cost deferrals	50	5	34
Estimated impact on 2013 pre-tax income	$ 259	$ 104	$ 161

The MPUC has scheduled deliberations for Aug. 6 and 8, 2013. The MPUC is expected to reach a decision on the issues at the deliberations and issue an order in September 2013.

NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with the interim rates of approximately $16 million and $47 million, as of March 31 and June 30, 2013, respectively.

NSP-Minnesota – North Dakota 2012 Electric Rate Case — In December 2012, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) to increase annual retail electric rates 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. In June 2013, we revised our rate increase to $16 million, reflecting updated information. There were no intervenors in this proceeding.

On July 17, 2013, NDPSC Advocacy Staff filed direct testimony prepared by their rate case consultants. Staff's testimony recommended a 9.0 percent ROE and other revenue requirement adjustments, which resulted in an overall rate reduction of approximately $2.1 million. Primary revenue requirement adjustments include:

(Millions of Dollars)	Revenue requirement adjustments as filed by the Staff
NSP-Minnesota revised request	$ 16.0
Use of a one month coincident peak demand allocator for rate base and operation expenses	(20.0)
ROE	(5.2)
Incentive compensation	(0.8)
Adjustment for various O&M expenses	(0.7)
Calculation of federal income taxes	6.3
Modified cost of capital and increased capital structure to 53.42 percent	1.4
Other, net	0.9
Recommended rate decrease	$ (2.1)

Additionally, NDPSC Staff recommends customers in NSP-Minnesota's North Dakota jurisdiction be excluded from paying for costs of certain purchased power agreements.

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

- Rebuttal Testimony – Aug. 12, 2013
- Technical Hearings – Aug. 27-28, 2013
- Initial Briefs – Sept. 20, 2013
- Reply Briefs/Proposed Findings – October 2013

A final NDPSC decision on the case is expected in the fourth quarter of 2013.

NSP-Wisconsin – Wisconsin 2014 Electric and Gas Rate Case — On May 31, 2013, 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, 2014. NSP-Wisconsin requested an overall increase in annual electric rates of $40.0 million, or 6.5 percent, and an increase in natural gas rates of $4.7 million, or 3.8 percent.

The rate filing is based on a 2014 forecast test year, a ROE of 10.4 percent, an equity ratio of 52.5 percent and a forecasted average net investment rate base of approximately $895.3 million for the electric utility and $89.8 million for the natural gas utility.

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

- Staff and Intervenor Direct Testimony – Oct. 4, 2013
- Rebuttal Testimony – Oct. 18, 2013
- Surrebuttal testimony – Oct. 28, 2013
- Hearing – Oct. 30, 2013
- Initial Brief – Nov. 13, 2013
- Reply Brief – Nov. 20, 2013

A PSCW decision is anticipated in December 2013, with final rates going into effect in January 2014.

NSP-Minnesota – Minnesota Resource Plan — In March 2013, the MPUC approved NSP-Minnesota's 2011-2025 Resource Plan. The MPUC ordered that a competitive acquisition process be conducted with the goal of adding approximately 500 megawatts (MW) of generation to the NSP System between 2017 and 2019. In February 2013, NSP-Minnesota also issued a Request for Proposal (RFP) for up to 200 MW of wind generation, to the extent that cost effective opportunities can be identified. Proposals for both RFPs may be for purchase power agreements (PPAs), self-build or contracts with a build-ownership transfer option. Bid proposals in response to the two RFPs were received in April 2013.

The competitive acquisition schedule is expected to be as follows:

- Continued evaluation of generation bids through contested case process managed by ALJ – August-October 2013
- ALJ will report to the MPUC which project should be selected – December 2013
- MPUC to make a final ruling – February-March 2014

On July 16, 2013, NSP-Minnesota filed a petition with the MPUC seeking approval of three 200 MW wind generation projects. NSP-Minnesota requested approval by October 2013. Potential projects are as follows:

- Odell is a 200 MW wind farm located near Mountain Lake, Minn. This is a 20-year PPA with Geronimo Energy. The project is expected to be operational in late 2015.
- Courtenay is a 200 MW wind farm located near Jamestown, N.D. This is a 20-year PPA with Geronimo Energy. The project is expected to operational by September 2015.
- Pleasant Valley is a 200 MW wind farm to be located near Austin, Minn. It will be developed and constructed by RES Americas, who will transfer ownership to NSP-Minnesota upon construction completion. Pleasant Valley is expected to operational by October 2015.
- In addition, we have been in discussions with RES Americas regarding an additional 150 MW build-ownership project. This may be brought to the MPUC and the NDPSC in separate petitions, depending on transmission costs which will be determined by Midcontinent Independent Transmission System Operator, Inc.

PSCo – Colorado 2013 Gas Rate Case — In December 2012, PSCo filed a multi-year request with the 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. The request is based on a 2013 forecast test year, a 10.5 percent ROE, a rate base of $1.3 billion and an equity ratio of 56 percent. PSCo is requesting an extension of its Pipeline System Integrity Adjustment (PSIA) rider mechanism to collect the costs associated with its pipeline integrity efforts, including accelerated 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 with a commitment to file a rate case to implement revised rates on Jan. 1, 2016.

In order to accommodate the procedural schedule, rates will go into effect as filed on Aug. 10, 2013, subject to refund.

On April 3, 2013, four parties filed answer testimony in the natural gas case. The CPUC Staff and Office of Consumer Counsel (OCC) recommended changes to the level of integrity management costs moved from the PSIA rider to base rates. PSCo's 2013 deficiency based on a Forecasted Test Year (FTY) net of PSIA changes was $45 million for 2013 and the revenue deficiency was $28.3 million based on a Historic Test Year (HTY).

The CPUC Staff recommended a rate reduction of $14.4 million, based on a HTY, an ROE of 9 percent and an equity ratio of 52 percent and other adjustments. The OCC recommended a rate increase of $0.5 million based on a HTY, an ROE of 9 percent and equity ratio of 51.03 percent and other adjustments. While the OCC did not recommend that the CPUC set rates using a FTY, they did calculate a revenue deficiency of $12.4 million for 2013. No other intervenor made ROE recommendations or specific recommendations regarding the revenue deficiency. The major adjustments to the test year proposed by the CPUC Staff and OCC are presented below.

(Millions of Dollars)	CPUC Staff	OCC
PSCo deficiency based on a HTY	$ 28.3	$ 28.3
ROE and capital structure adjustments	(20.8)	(20.0)
Move to a 13 month average from year end rate base	(5.7)	(3.2)
Remove pension asset	(5.9)	-
Remove incentive compensation	(3.5)	(0.2)
Challenge known and measurable	-	(9.0)
Eliminate depreciation annualization	-	(1.8)
Revenue adjustments	(4.1)	(1.4)
Resulting tax impacts	1.5	4.7
Other adjustments	(4.2)	3.1
Recommendation	$ (14.4)	$ 0.5

On April 26, 2013, the CPUC Staff filed supplemental testimony recommending an additional net disallowance of $1.6 million for adjustments and corrections.

On April 29, 2013, PSCo filed rebuttal testimony and revised its requested annual rate increase to $44.8 million for 2013, with subsequent step increases of $9.0 million for 2014 and $10.9 million for 2015, based on an ROE of 10.3 percent. PSCo agreed to recover approximately $3.5 million of revenue requirement in the PSIA, rather than through base rates and accepted the CPUC Staff's recommendation to use deferred accounting to accommodate property tax increases.

Hearings were held in May 2013. An ALJ recommendation is anticipated in August 2013 and a decision is expected in the third quarter of 2013.

PSCo – Colorado 2013 Steam Rate Case — In December 2012, PSCo filed a request 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. The request is based on a 2013 forecast test year, a 10.5 percent ROE, a rate base of $21 million for steam and an equity ratio of 56 percent. Final rates are expected to be effective in the fourth quarter of 2013.

On July 23, 2013, PSCo, CPUC Staff, the OCC and Colorado Energy Consumers representing the Building Owners Management Association filed an unopposed joint motion for the CPUC to vacate the current procedural schedule and to set a date of Aug. 12, 2013, by which the parties shall file either: (i) a comprehensive settlement agreement resolving all issues presented in this matter; or (ii) a consensus revised procedural schedule.

PSCo – Colorado 2011 Electric Resource Plan (ERP), 2013 All-Source Solicitation and Renewable Energy Standard (RES) Plan — In January 2013, the CPUC approved with modifications the 2011 ERP. Consistent with the ERP, in March 2013, PSCo issued an All-Source RFP for 250 MW by the end of 2018. Proposals for the All-Source RFP may be for PPAs, self-build or contracts with a build-ownership transfer option. PSCo also issued a separate wind RFP for PPAs only. Bid proposals in response to the Wind RFP were received in April 2013. The CPUC recommended that PSCo include 548 MW of wind in its resource portfolios for modeling purposes. The CPUC approved the inclusion of the least cost wind bid in portfolios for modeling purposes and sought additional information regarding the wind bids in the September All-Source evaluation assessment before approving any of the acquisitions. In July 2013, the 2014 RES plan was filed.

Next steps in the 2013 All-Source RFP schedule are expected to be as follows:

- Delivery of the All-Source evaluation assessment report to CPUC – September 2013
- CPUC evaluation and regulatory approval of wind-based generation proposals – October 2013
- CPUC evaluation and regulatory approval of All-Source generation proposals – December 2013

SPS – Texas 2012 Electric Rate Case — In November 2012, SPS filed an electric rate case in Texas with the Public Utility Commission of Texas (PUCT) 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.

In April 2013, the parties filed a settlement agreement in which SPS' base rate will increase by $37 million, effective May 1, 2013, on an interim basis pending the PUCT's approval of the settlement, and by an additional $13.8 million on Sept. 1, 2013. In addition, the settlement allows SPS to file a transmission cost recovery adjustment rider in the fourth quarter of 2013 and for those rates to become effective on an interim basis in January 2014. Under the settlement, SPS cannot file another base rate case in 2013, but there are no restrictions on SPS filing a base rate case in 2014. On June 6, 2013, the PUCT approved the settlement without modification.

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 $479.8 million and an equity ratio of 53.89 percent.

In March 2013, the NMPRC ruled that SPS' case, as originally filed, was incomplete due to confidential exhibits to testimony and schedules being included in SPS' direct case, and directed the hearing examiner to review SPS' claims of confidentiality and to determine the date the filing is complete. After SPS made filings to address the NMPRC's concern about the confidential documents, the hearing examiner determined that SPS' application was completed on April 12, 2013. The NMPRC has suspended the tariffs for an initial nine month period beyond that date, or until Jan. 11, 2014. The NMPRC has authority to suspend the rates for an additional three months beyond the initial nine month period, or until April 11, 2014. On June 19, 2013, SPS revised its requested rate increase to $43.3 million.

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

- Staff/Intervenor Direct Testimony – Aug. 22, 2013
- Rebuttal Testimony – Sept. 9, 2013
- Evidentiary Hearings – Sept. 16-27, 2013

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:

- Rate case outcomes consistent with current expectations.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales are projected to increase by approximately 0.0 to 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to increase by approximately 2 percent.
- 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 $20 million to $25 million over 2012 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $40 million to $45 million from 2012 levels.
- AFUDC — equity is projected to increase approximately $20 million to $25 million over 2012 levels.
- The effective tax rate is projected to be approximately 33 percent to 35 percent.
- Average common stock and equivalents are projected to be approximately 497 million shares.

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

	Three Months Ended June 30	
	2013	**2012**
Operating revenues:		
Electric and natural gas	$ 2,561,198	$ 2,258,142
Other	17,715	16,526
Total operating revenues	2,578,913	2,274,668
Income from continuing operations	196,882	183,075
Loss from discontinued operations, net of tax	(25)	(15)
Net income	$ 196,857	$ 183,060
Earnings available to common shareholders	$ 196,857	$ 183,060
Weighted average diluted common shares outstanding	498,036	488,017
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 0.44	$ 0.41
Xcel Energy Inc. and other costs	(0.04)	(0.03)
GAAP diluted earnings per share	$ **0.40**	$ **0.38**

	Six Months Ended June 30	
	2013	**2012**
Operating revenues:		
Electric and natural gas	$ 5,322,990	$ 4,815,959
Other	38,772	36,788
Total operating revenues	5,361,762	4,852,747
Income from continuing operations	433,470	366,844
(Loss) income from discontinued operations, net of tax	(43)	109
Net income	$ 433,427	$ 366,953
Earnings available to common shareholders	$ 433,427	$ 366,953
Weighted average diluted common shares outstanding	494,303	488,006
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	$ 0.96	$ 0.82
Xcel Energy Inc. and other costs	(0.08)	(0.07)
GAAP diluted earnings per share	**$ 0.88**	**$ 0.75**
Book value per share	$ 18.70	$ 17.59