414 Nicollet Mall
Minneapolis, MN 55401

May 1, 2014

XCEL ENERGY
FIRST QUARTER 2014 EARNINGS REPORT

- GAAP (generally accepted accounting principles) 2014 first quarter earnings per share were $0.52 compared with $0.48 per share in 2013.
- We achieved constructive rate case outcomes in North Dakota and New Mexico.
- The Board of Directors approved a 7 percent dividend rate increase to $1.20 per share.
- Xcel Energy reaffirms 2014 ongoing earnings guidance of $1.90 to $2.05 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2014 first quarter GAAP earnings of $261 million, or $0.52 per share, compared with $237 million, or $0.48 per share, in the same period in 2013.

First quarter 2014 earnings were higher due to increased electric and natural gas margins primarily due to colder weather at NSP-Minnesota and NSP-Wisconsin and rate increases in several jurisdictions. These positive factors were partially offset by increased operating and maintenance expenses and property taxes.

"We are pleased to report a solid start to the year with many significant accomplishments, including strong first quarter financial results," stated Chairman, President and Chief Executive Officer Ben Fowke. "Our customers in our Northern service territories experienced extremely cold temperatures that positively impacted our quarterly earnings by four cents per share, when compared to first quarter 2013, and I'm proud to report our system operated well despite the harsh weather, with no major service disruptions."

"During the quarter, we received constructive regulatory outcomes in two of our states. In North Dakota, the commission approved our four-year - multi-year settlement in our electric rate case and the New Mexico Commission granted an electric rate increase that was in-line with our revised request."

"We have much to accomplish in 2014, but are pleased with our current momentum. Earlier in the year, the Board of Directors approved a 7 percent dividend increase, which exceeds our targeted annual dividend growth objective of 4 to 6 percent. We also reaffirm our 2014 ongoing earnings guidance of $1.90 to $2.05 per share," said Fowke.

At 9:00 a.m. CDT today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in 5 to 10 minutes prior to the start and follow the operator's instructions.

US Dial-In:	(877) 941-0844
International Dial-In:	(480) 629-9835
Conference ID:	4675178

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 1:00 p.m. CDT on May 1 through 11:59 p.m. CDT on May 2.

Replay Numbers	
US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4675178#

Except for the historical statements contained in this release, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2014 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, 2013.

For more information, contact:

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This information is not given in connection with any sale, offer for sale or offer to buy any security.

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

	Three Months Ended March 31	
	2014	2013
Operating revenues		
Electric	$ 2,301,710	$ 2,092,196
Natural gas	879,688	669,596
Other	21,206	21,057
Total operating revenues	3,202,604	2,782,849
Operating expenses		
Electric fuel and purchased power	1,067,321	925,043
Cost of natural gas sold and transported	623,828	439,375
Cost of sales — other	9,129	8,411
Operating and maintenance expenses	560,143	529,231
Conservation and demand side management program expenses	77,546	64,032
Depreciation and amortization	245,943	248,706
Taxes (other than income taxes)	124,702	113,427
Total operating expenses	2,708,612	2,328,225
Operating income	493,992	454,624
Other income, net	3,201	3,922
Equity earnings of unconsolidated subsidiaries	7,438	7,577
Allowance for funds used during construction — equity	21,907	19,754
Interest charges and financing costs		
Interest charges — includes other financing costs of $5,792 and $5,809, respectively	139,094	139,631
Allowance for funds used during construction — debt	(9,548)	(8,758)
Total interest charges and financing costs	129,546	130,873
Income before income taxes	396,992	355,004
Income taxes	135,771	118,434
Net income	$ 261,221	$ 236,570
Weighted average common shares outstanding:		
Basic	499,523	489,781
Diluted	499,746	490,531
Earnings per average common share:		
Basic	$ 0.52	$ 0.48
Diluted	0.52	0.48
Cash dividends declared per common share	$ 0.30	$ 0.27

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Investor Relations Earnings Release (Unaudited)

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

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The 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. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of earnings results. We believe 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 measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	**2014**	**2013**
Public Service Company of Colorado (PSCo)	$ 0.24	$ 0.24
NSP-Minnesota	0.21	0.21
NSP-Wisconsin	0.05	0.04
Southwestern Public Service Company (SPS)	0.04	0.02
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility	0.55	0.52
Xcel Energy Inc. and other costs	(0.03)	(0.04)
GAAP diluted EPS	**$ 0.52**	**$ 0.48**

PSCo — PSCo's earnings were flat for the first quarter of 2014. Higher electric and natural gas rates and sales growth were offset by increased property taxes, depreciation, and accruals associated with electric earnings test refund obligations.

NSP-Minnesota — NSP-Minnesota's earnings were flat for the first quarter of 2014. Colder weather and interim electric rate increases in Minnesota (subject to refund) and North Dakota were offset by higher operating and maintenance (O&M) expenses and lower allowance for funds used during construction (AFUDC). In addition, results for the first quarter of 2013 reflect interim rates in Minnesota, which were recorded at a level higher than the final rates implemented later in 2013.

NSP-Wisconsin — NSP-Wisconsin's earnings increased $0.01 per share for the first quarter of 2014. Higher electric and natural gas margins, due to colder weather and an electric rate increase effective in January 2014, were partially offset by higher O&M expenses.

SPS — SPS' earnings increased $0.02 per share for the first quarter of 2014. The positive impact of higher electric rates and interim transmission rider revenue in Texas were partially offset by increased O&M expenses.

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

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2013 GAAP diluted EPS	**$ 0.48**
Components of change — 2014 vs. 2013	
Higher electric margins	0.08
Higher natural gas margins	0.03
Higher O&M expenses	(0.04)
Higher conservation and demand side management (DSM) program expenses	(0.02)
Dilution from equity issued through the at-the-market program, direct stock purchase plan and benefit plans	(0.01)
Higher taxes (other than income taxes)	(0.01)
Other, net	0.01
2014 GAAP diluted EPS	**$ 0.52**

Note 2. Regulated Utility Results

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales while, 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.

There was no impact on sales in the first quarter of 2014 due to THI or CDD. The percentage increase in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
HDD	14.1%	3.6%	9.3%

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

	Three Months Ended March 31		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
Retail electric	$ 0.031	$ 0.004	$ 0.027
Firm natural gas	0.018	0.009	0.009
Total	$ 0.049	$ 0.013	$ 0.036

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

	Three Months Ended March 31				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Actual					
Electric residential	5.8%	8.2%	1.1%	9.6%	4.8%
Electric commercial and industrial [(a)]	2.8	6.4	1.4	4.5	3.0
Total retail electric sales	3.7	7.0	1.5	5.4	3.6
Firm natural gas sales [(b)]	17.2	19.8	(0.4)	N/A	6.5

	Three Months Ended March 31				
	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	Xcel Energy
Weather Normalized					
Electric residential	0.5%	0.6%	1.3%	2.8%	1.1%
Electric commercial and industrial [(a)]	1.5	4.6	1.1	4.5	2.3
Total retail electric sales	1.2	3.3	1.4	4.0	2.0
Firm natural gas sales [(b)]	2.6	1.2	4.6	N/A	3.7

(a) The growth in the NSP-Wisconsin electric commercial and industrial (C&I) class is primarily driven by increases in the manufacturing and energy sectors. The growth in the SPS electric C&I class is primarily the result of continued rapid expansion of oilfield development.

(b) As normal weather conditions are typically defined as a 30-year average of actual historical weather conditions, significant weather fluctuations in periods of low demand may result in large percentage changes on small volumes. Extreme weather variations and additional factors such as windchill and cloud cover may not be fully reflected.

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 March 31	
(Millions of Dollars)	**2014**	**2013**
Electric revenues	$ 2,302	$ 2,092
Electric fuel and purchased power	(1,067)	(925)
Electric margin	$ 1,235	$ 1,167

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

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Retail rate increases [a]	$ 38
Estimated impact of weather	21
Conservation and DSM program revenues (offset by expenses)	13
Retail sales growth, excluding weather impact	12
Transmission revenue, net of costs	12
PSCo earnings test refund obligations	(11)
Other, net	(17)
Total increase in electric margin	$ 68

[a] The retail rate increases include final rates in Texas, Wisconsin, Colorado and North Dakota, and interim rates in Minnesota (subject to refund). See Note 4 for further discussion of rates and regulation.

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:

(Millions of Dollars)	Three Months Ended March 31 2014	2013
Natural gas revenues	$ 880	$ 670
Cost of natural gas sold and transported	(624)	(439)
Natural gas margin	$ 256	$ 231

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

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Retail rate increase, net of refund (Colorado)	$ 9
Estimated impact of weather	7
Pipeline system integrity adjustment rider (Colorado), partially offset in O&M expenses	4
Retail sales growth	3
Other, net	2
Total increase in natural gas margin	$ 25

O&M Expenses — O&M expenses increased $30.9 million, or 5.8 percent, for the first quarter of 2014 compared with the same period in 2013. The increase in O&M expenses for the first quarter reflects timing issues and overall increases in expense levels, as summarized in the table below. Xcel Energy continues to anticipate annual O&M expenses will increase 2 percent to 3 percent for 2014.

(Millions of Dollars)	Three Months Ended March 31 2014 vs. 2013
Nuclear plant operations and amortization	$ 12
Electric and gas distribution expenses	10
Transmission costs	2
Other, net	7
Total increase in O&M expenses	$ 31

- Nuclear cost increases were related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Electric and gas distribution expenses were primarily driven by increased maintenance activities attributable to weather and storm related costs, vegetation management, repairs and amounts related to pipeline system integrity; and
- Transmission costs were primarily due to higher substation maintenance expenditures.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $13.5 million, or 21.1 percent, for the first quarter of 2014 compared with the same period in 2013. The higher expenses were primarily attributable to higher rider rates and higher volume for recovery of electric conservation program expenses at NSP-Minnesota. Conservation costs are recovered from customers and expensed on a kilowatt hour basis, so increased sales due to cold winter temperatures or hot summer temperatures will increase revenue and expense. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization decreased $2.8 million, or 1.1 percent, for the first quarter of 2014 compared with the same period in 2013. As part of the 2013 and pending 2014 Minnesota electric rate cases, depreciation expense during the first quarter of 2014 was reduced by $28.3 million, and reflects the acceleration of the amortization of the excess depreciation reserve. This decrease was partially offset by depreciation and amortization associated with normal system expansion. See Note 4 for further discussion of the Minnesota 2014 Multi-Year Electric Rate Case.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11.3 million, or 9.9 percent, for the first quarter of 2014 compared with the same period in 2013. The increase was due to higher property taxes primarily in Minnesota and Colorado.

AFUDC, Equity and Debt — AFUDC increased $2.9 million for the first quarter of 2014 compared with the same period in 2013. The increase was primarily due to construction related to the Clean Air Clean Jobs Act (CACJA) and the expansion of transmission facilities.

Interest Charges — Interest charges decreased $0.5 million, or 0.4 percent, for the first quarter of 2014 compared with the same period in 2013. The decrease was primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels.

Income Taxes **—** Income tax expense increased $17.3 million for the first quarter of 2014 compared with the same period in 2013. The increase in income tax expense was primarily due to higher pretax earnings in 2014.

The effective tax rate (ETR) was 34.2 percent for the first quarter of 2014 compared with 33.4 percent for the same period in 2013. The lower ETR for 2013 was primarily due to the recognition of research and experimentation credits in 2013 due to the passage of the American Taxpayer Relief Act and a tax benefit for a carryback claim related to 2013. These were partially offset by the successful resolution of a 2010-2011 Internal Revenue Service audit issue in 2014.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	March 31, 2014	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.3	1%
Short-term debt	0.8	4
Long-term debt	11.2	51
Total debt	12.3	56
Common equity	9.7	44
Total capitalization	$ 22.0	100%

Credit Facilities — As of April 29, 2014, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 800.0	$ 448.0	$ 352.0	$ 0.5	$ 352.5
PSCo	700.0	83.5	616.5	0.3	616.8
NSP-Minnesota	500.0	285.9	214.1	0.9	215.0
SPS	300.0	212.0	88.0	0.4	88.4
NSP-Wisconsin	150.0	83.0	67.0	1.0	68.0
Total	$ 2,450.0	$ 1,112.4	$ 1,337.6	$ 3.1	$ 1,340.7

(a) These credit facilities expire in July 2017.

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

During the second quarter of 2014, Xcel Energy Inc. and its utility subsidiaries anticipate extending their existing revolving credit agreements.

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).

On Jan. 31, 2014, Moody's upgraded the credit ratings of Xcel Energy and its subsidiaries by one notch. The outlook is stable.

As of April 29, 2014, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

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

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

Financing — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

In March 2014, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044.

During the remainder of 2014, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- NSP-Minnesota may issue approximately $300 million of first mortgage bonds;
- SPS may issue approximately $150 million of first mortgage bonds; and
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds.

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. During the three months ended March 31, 2014, Xcel Energy Inc. entered into sales transactions for 2.6 million shares of common stock with net proceeds of approximately $78 million, which includes transactions initiated but not settled as of March 31, 2014.

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

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

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve which the MPUC approved in NSP-Minnesota's last electric rate case and the use of expected funds from the U.S. Department of Energy (DOE) for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello life cycle management (LCM)/extended power uprate (EPU) project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island EPU project. NSP-Minnesota may file a petition for deferred accounting regarding these Monticello costs later in 2014.

The rate request, moderation plan, interim rate adjustments, customer bill impacts and certain impacts on expenses are detailed in the table below:

(Millions of Dollars)	2014	Percentage Increase	2015	Percentage Increase
Pre-moderation deficiency	**$ 274**		**$ 81**	
Moderation change compared to prior year:				
Depreciation reserve	(81)		53	
DOE settlement proceeds	—		(36)	
Filed rate request	**193**	**6.9%**	**98**	**3.5%**
Interim rate adjustments	(66)		66	
Impact on customer bill	**127**	**4.6%**	**164**	**5.6%**
Potential expense deferral	16		—	
Depreciation expense - reduction/(increase)	81		(46)	
Recognition of DOE settlement proceeds	—		36	
Pre-tax impact on operating income	**$ 224**		**$ 154**	

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

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

- Direct Testimony — June 5, 2014;
- Rebuttal Testimony — July 7, 2014;
- Surrebuttal Testimony — Aug. 4, 2014;
- Evidentiary Hearing — Aug. 11-18, 2014;
- Reply Brief — Oct. 14, 2014; and
- Administrative Law Judge (ALJ) Report — Dec. 22, 2014.

A final MPUC decision is anticipated in March 2015.

NSP-Minnesota – Nuclear Project Prudence Investigation — The MPUC has initiated an investigation to determine whether the costs in excess of the $320 million included in the certificate of need (CON) for NSP-Minnesota's Monticello LCM/EPU project were prudent. The final costs for the Monticello LCM/EPU project were approximately $665 million.

In October 2013, NSP-Minnesota filed a report to further support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and (3) additional Nuclear Regulatory Commission (NRC) licensing related requests over the five-plus year application process. NSP-Minnesota has provided information that the cost deviation is in line with similar upgrade projects undertaken by other utilities and the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and has begun the process to comply with the license requirements for higher power levels, subject to NRC oversight and review.

At the direction of the MPUC, the Minnesota Department of Commerce (DOC) has retained a consultant to assist in their review. The consultant, Global Energy and Water Consulting, LLC is covering the cost split between LCM and EPU; reasons for the cost increases; project management and oversight; and the prudence of scope changes among others. The results and any recommendations from the conclusion of this prudence proceeding are expected to be considered by the MPUC in NSP-Minnesota's 2014 Minnesota electric rate case. The next steps in the procedural schedule are expected to be as follows:

- Direct Testimony — July 2, 2014;
- Rebuttal Testimony — Aug. 26, 2014;
- Surrebuttal Testimony — Sept. 19, 2014;
- Hearing — Sept. 29 - Oct. 3, 2014;
- Reply Brief — Nov. 21, 2014; and
- ALJ Report — Dec. 31, 2014.

A final MPUC decision is anticipated in the first quarter of 2015.

NSP-Minnesota – North Dakota 2013 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 was based on a 2013 forecast test year (FTY), 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 February 2014, the NDPSC approved a four-year rate plan settlement. The approved plan will provide increased revenues of approximately $7.4 million, $9.4 million and $10.1 million, an annual rate increase of 4.9 percent for 2013, 2014 and 2015 respectively, with no increase in 2016. Additionally, the rate plan includes a gradually increasing ROE of 9.75, 10.0, 10.0 and 10.25 percent for 2013 through 2016, respectively. Final rates for 2013 and the 2014 rate increase went into effect May 1, 2014. The 2015 rate increase will take effect Jan. 1, 2015.

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

In September 2013, NSP-Minnesota recommended a self-build, 215 MW natural gas combustion turbine at its Black Dog site and a purchased power agreement (PPA) with either Calpine's Mankato combined cycle natural gas project or Invenergy's Cannon Falls combustion turbine natural gas project. In October 2013, the DOC recommended the MPUC approve NSP-Minnesota's proposal.

In December 2013, the ALJ recommended the MPUC select a combination of a 100 MW solar proposal by Geronimo Energy, LLC and capacity credits offered by Great River Energy.

At a hearing in March 2014, the MPUC appeared to favor the Geronimo Energy, LLC (solar) proposal and instructed NSP-Minnesota to negotiate PPAs. In addition, the MPUC directed NSP-Minnesota to negotiate PPAs with Calpine (combined cycle) and Invenergy (combustion turbine) and develop pricing for the Black Dog site. NSP-Minnesota is awaiting a written order. A MPUC decision is anticipated in late 2014. The next Minnesota resource plan is expected to be filed in January 2015.

In early 2013, NSP-Minnesota also issued a request for proposal (RFP) for wind generation and subsequently sought commission approval for four wind projects.

- A 200 MW ownership project for the Pleasant Valley wind farm in Minnesota;
- A 150 MW ownership project for the Border Winds wind farm in North Dakota;
- A 200 MW PPA with Geronimo Energy, LLC for the Odell wind farm in Minnesota; and
- A 200 MW PPA with Geronimo Energy, LLC for the Courtenay wind farm in North Dakota.

In October 2013, the MPUC approved the four wind projects. In 2014, the NDPSC approved the prudence of the Border Winds project as part of the rate case settlement and determined it will address the Pleasant Valley project at a later date. The feasibility of the Border Winds and Pleasant Valley projects are also dependent on the finalization of estimated transmission costs, which Midcontinent Independent Transmission System Operator, Inc. (MISO) is expected to determine in 2014.

On April 22, 2014, NSP-Minnesota filed a RFP for up to 100 MW's of solar generation resources. Proposals will be accepted through June 2014. NSP-Minnesota will evaluate bids from that time until mid-August and anticipates filing selected bids with the MPUC in October 2014.

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

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

In April 2014, SPS revised its requested rate increase to approximately $48.1 million, or 5.3 percent, based on updated information. The following table summarizes SPS' revised request:

(Millions of Dollars)	SPS Request
Adjusted base rate increase	$ 76.9
Resetting TCRF	(12.9)
Credit to customers for gain on sale to Lubbock moved to a rider	(4.9)
Adjusted net increase in base revenue	59.1
Fuel clause offsets	(11.0)
Adjusted retail customer net bill impact	$ 48.1

The PUCT has suspended SPS' proposed rates through Oct. 31, 2014. If the PUCT has not issued a final order by July 11, 2014, then SPS' current rates will not change, but final rates, when approved by the PUCT, will be made effective retroactive to July 12, 2014. SPS, intervenors and other parties have commenced settlement negotiations.

Next steps in the procedural schedule are as follows:

- Intervenor testimony — May 22, 2014;
- PUCT Staff testimony — May 29, 2014;
- Cross-rebuttal testimony — June 12, 2014;
- Rebuttal testimony — June 16, 2014;
- Evidentiary hearing — June 25, 2014; and
- A PUCT decision and implementation of final rates are anticipated in the third quarter of 2014.

SPS – New Mexico 2014 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 effective in 2014. The rate filing was based on a 2014 FTY, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent.

In September 2013, SPS filed rebuttal testimony, revising its requested rate increase to $32.5 million, based on updated information and an ROE of 10.25 percent. This reflects a base and fuel increase of $20.9 million, an increase of rider revenue of $12.1 million and a decrease to other of $0.5 million.

In March 2014, the NMPRC approved an overall increase of approximately $33.1 million. The increase includes: an ROE of 9.96 percent, an equity ratio of 53.89 percent, allowance of the prepaid pension asset in rate base of approximately $2.4 million, allowance of certain non-labor operating and maintenance escalations and recovery of approximately $18.1 million of renewable energy costs through rider revenue instead of base revenue. As a result of a change in the amount of fuel costs recovered through base rates, SPS will no longer be required to credit customers for $2.3 million through the fuel clause adjustment. Final rates were effective April 5, 2014. On April 25, 2014, the New Mexico Attorney General filed a request for rehearing. The rehearing request is pending with the NMPRC, which has until May 15, 2014 to grant or deny the request.

The following table summarizes the NMPRC's approval from SPS' revised request:

(Millions of Dollars)	NMPRC Approval
SPS revised request, September 2013	$ 32.5
Fuel clause adjustment credit — non-renewable energy costs	2.3
SPS revised request, fuel adjusted	34.8
ROE (9.96 percent)	(1.2)
Rate rider adjustment — renewable energy costs	6.0
Base rate reduction for rate rider — renewable energy costs	(6.0)
Other, net	(0.5)
Approved increase, March 2014	$ 33.1
Means of recovery:	
Base revenue	$ 12.7
Rider revenue	18.1
Fuel clause	2.3
	$ 33.1

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

Xcel Energy Earnings Guidance — Xcel Energy's 2014 ongoing earnings guidance is $1.90 to $2.05 per share. Key assumptions related to 2014 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to increase by up to approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to range from a decline of approximately 1.0 percent to an increase of approximately 1.0 percent.
- Capital rider revenue is projected to increase by $50 million to $60 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $40 million to $50 million over 2013 levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $50 million to $60 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $0 to $10 million from 2013 levels.
- AFUDC — equity is projected to increase approximately $5 million to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 507 million shares.

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on a normalized 2013 EPS of $1.90 per share, which represented the mid-point of our 2013 earnings guidance range;
- Deliver annual dividend increases of 4 percent to 6 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is discussed above in the introduction to the Notes to Investor Relations Earnings Release.

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

	Three Months Ended March 31	
	2014	**2013**
Operating revenues:		
Electric and natural gas	$ 3,181,398	$ 2,761,792
Other	21,206	21,057
Total operating revenues	3,202,604	2,782,849
Net income	$ 261,221	$ 236,570
Weighted average diluted common shares outstanding	499,746	490,531
Components of EPS — Diluted		
Regulated utility	$ 0.55	$ 0.52
Xcel Energy Inc. and other costs	(0.03)	(0.04)
GAAP diluted EPS	**$ 0.52**	**$ 0.48**
Book value per share	$ 19.45	$ 18.53